UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

2019 FORM 10-K

(Mark One)
☑ **Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2019
OR

☐ **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from _________ to________

Commission file number: 001-12935

DENBURY RESOURCES INC.
(Exact name of Registrant as specified in its charter)

Delaware	**20-0467835**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
5320 Legacy Drive,	
Plano, TX	**75024**
(Address of principal executive offices)	*(Zip Code)*
Registrant's telephone number, including area code:	**(972) 673-2000**

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class:	Trading Symbol:	Name of Each Exchange on Which Registered:
Common Stock $.001 Par Value	DNR	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 (§232.405 of this chapter) of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company," and "emerging growth company" in Rule 12-b2 of the Exchange Act.

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the registrant's common stock held by non-affiliates, based on the closing price of the registrant's common stock as of the last business day of the registrant's most recently completed second fiscal quarter was $565,329,480.

The number of shares outstanding of the registrant's Common Stock as of January 31, 2020, was 506,382,897.

DOCUMENTS INCORPORATED BY REFERENCE

Document:	Incorporated as to:
1. Notice and Proxy Statement for the Annual Meeting of Stockholders to be held May 28, 2020.	1. Part III, Items 10, 11, 12, 13, 14

Denbury Resources Inc.

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Denbury Resources Inc.

Glossary and Selected Abbreviations

Bbl	One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.
Bbls/d	Barrels of oil or other liquid hydrocarbons produced per day.
Bcf	One billion cubic feet of natural gas or CO_2.
BOE	One barrel of oil equivalent, using the ratio of one barrel of crude oil, condensate or natural gas liquids to 6 Mcf of natural gas.
BOE/d	BOEs produced per day.
Btu	British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit (°F).
CO_2	Carbon dioxide.
EOR	Enhanced oil recovery. In the context of our oil production, EOR is also referred to as tertiary recovery. Primary types of EOR include thermal, gas injection (such as natural gas, nitrogen, or CO_2) and chemical injection (such as the use of polymers).
Finding and development costs	The average cost per BOE to find and develop proved reserves during a given period. It is calculated by dividing (a) costs, which include the sum of (i) the total acquisition, exploration and development costs incurred during the period plus (ii) future development and abandonment costs related to the specified property or group of properties, by (b) the sum of (i) the change in total proved reserves during the period plus (ii) total production during that period.
GAAP	Accounting principles generally accepted in the United States of America.
MBbls	One thousand barrels of crude oil or other liquid hydrocarbons.
MBOE	One thousand BOEs.
Mcf	One thousand cubic feet of natural gas or CO_2 at a temperature base of 60 degrees Fahrenheit (°F) and at the legal pressure base (14.65 to 15.025 pounds per square inch absolute) of the state or area in which the reserves are located or sales are made.
Mcf/d	One thousand cubic feet of natural gas or CO_2 per day.
MMBbls	One million barrels of crude oil or other liquid hydrocarbons.
MMBOE	One million BOEs.
MMBtu	One million Btus.
MMcf	One million cubic feet of natural gas or CO_2.
MMcf/d	One million cubic feet of natural gas or CO_2 produced per day.
Noncash fair value gains (losses) on commodity derivatives	The net change during the period in the fair market value of commodity derivative positions. Noncash fair value gains (losses) on commodity derivatives is a non-GAAP measure and makes up only a portion of "Commodity derivatives expense (income)" in the Consolidated Statements of Operations, which also includes the impact of settlements on commodity derivatives during the period. Its use is further discussed in *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Operating Results Table*.
NYMEX	The New York Mercantile Exchange. In the context of prices received for oil and natural gas, NYMEX prices represent the West Texas Intermediate benchmark price for crude oil and Henry Hub benchmark price for natural gas.
Probable Reserves*	Reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.
Proved Developed Reserves*	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved Reserves*	Reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved Undeveloped Reserves*	Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells, in each case where a relatively major expenditure is required.
PV-10 Value	The estimated future gross revenue to be generated from the production of proved reserves, net of estimated future production, development and abandonment costs, and before income taxes, discounted to a present value using an annual discount rate of 10%. PV-10 Values were prepared using average hydrocarbon prices equal to the unweighted arithmetic average of hydrocarbon prices on the first day of each month within the 12-month period preceding the reporting date. PV-10 Value is a non-GAAP measure and does not purport to represent the fair value of our oil and natural gas reserves; its use is further discussed in Item 1, *Business and Properties – Non-GAAP Financial Measures and Reconciliations*.
Tcf	One trillion cubic feet of natural gas or CO_2.
Tertiary Recovery	A term used to represent techniques for extracting incremental oil out of existing oil fields (as opposed to primary and secondary recovery or “non-tertiary” recovery). See also “EOR.”

* This definition is an abbreviated version of the complete definition set forth in Rule 4-10(a) of Regulation S-X. For the complete definition see:
http://www.ecfr.gov/cgi-bin/text-idx?SID=2d916841db86d079fa060fa63b08d34e&mc=true&node=se17.3.210_14_610&rgn=div8.

Denbury Resources Inc.

PART I

Item 1. Business and Properties

GENERAL

Denbury Resources Inc., a Delaware corporation, is an independent oil and natural gas company with 230.2 MMBOE of estimated proved oil and natural gas reserves as of December 31, 2019, of which 98% is oil. Our operations are focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of our properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to CO_2 enhanced oil recovery operations.

As part of our corporate strategy, we are committed to strong financial discipline, efficient operations and creating long-term value for our shareholders through the following key principles:

- target specific regions where we either have, or believe we can create, a competitive advantage as a result of our ownership or use of CO_2 reserves, oil fields and CO_2 infrastructure;
- secure properties where we believe additional value can be created through tertiary recovery operations and a combination of other exploitation, development, exploration and marketing techniques;
- acquire properties that give us a majority working interest and operational control or where we believe we can ultimately obtain it;
- maximize the value and cash flow generated from our operations by increasing production and reserves while controlling costs;
- optimize the timing and allocation of capital among our investment opportunities to maximize the rates of return on our investments;
- exercise financial discipline by attempting to balance our development capital expenditures with our cash flows from operations; and
- attract and maintain a highly competitive team of experienced and incentivized personnel.

Denbury has been publicly traded on the New York Stock Exchange since 1997. Our corporate headquarters is located at 5320 Legacy Drive, Plano, Texas 75024, and our phone number is 972-673-2000. At December 31, 2019, we had 806 employees, 451 of whom were employed in field operations or at our field offices. We make our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports, filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, available free of charge on or through our website, www.denbury.com, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The SEC also maintains a website, http://www.sec.gov, which contains periodic reports on Forms 8-K, 10-Q and 10-K filed with the SEC, along with other reports, proxy and information statements and other information filed by Denbury. Throughout this Annual Report on Form 10-K ("Form 10-K") we use the terms "Denbury," "Company," "we," "our" and "us" to refer to Denbury Resources Inc. and, as the context may require, its subsidiaries.

2019 BUSINESS DEVELOPMENTS

Since our production is 97% oil, oil prices generally constitute the single largest variable in our operating results. Over the last several years, NYMEX oil prices have been extremely volatile, decreasing to a low of $26 in early 2016 and gradually improving to hit a three-year peak of $76 in October 2018, before retreating to the low $40s in late December 2018 and generally averaging in the low $50s to mid $60s range throughout 2019. Throughout this time, we have focused primarily on preservation of cash and liquidity, together with cost reductions and debt management, rather than concentration on expansion and growth. Our 2019 key accomplishments and business developments included the following:

- Generated $494.1 million of cash flow from operations ($408.8 million after reducing for interest payments treated as debt reduction), significantly exceeding our $273.6 million of incurred development capital expenditures and capitalized interest in 2019.

- Reduced our debt principal by $250.5 million and significantly improved our debt maturity profile, ending the year with no outstanding borrowings on the Company's senior secured bank credit facility.

- Continued progress on the CO_2 enhanced oil recovery development project at Cedar Creek Anticline ("CCA"), Denbury's largest oil field, to access the potential for significant long-term oil production and cash flow from this key asset, with project activities and capital primarily related to procurement of the pipe and preparation for installation of the CO_2 pipeline to CCA.

- Improved our leverage ratio to 3.7x during 2019 from 4.2x during 2018 (ratio of net debt (debt principal less cash) to Adjusted EBITDAX (a non-GAAP measure)) (see *Non-GAAP Financial Measures and Reconciliations*).

- Reduced general and administrative expenses (excluding $18.6 million of severance expense related to a voluntary separation program) by $7.1 million, a 10% reduction from 2018 amounts.

- Continued to optimize our oil and natural gas asset portfolio through the following: (1) sold Citronelle Field for approximately $10 million in July 2019 and (2) entered into an agreement in December 2019 to sell half of our nearly 100% working interests in four conventional southeast Texas oil fields for $50 million and a carried interest in ten wells to be funded and drilled by the purchaser, which is currently expected to occur in March 2020 (the "Pending Gulf Coast Working Interests Sale").

- Continued the monetization of valuable surface land with no active oil and natural gas operations around Houston, Texas, including (1) the sale of multiple parcels primarily around Houston, Texas in transactions totaling $14 million in 2019 and (2) entered into a contract to sell acreage around Houston, Texas for $32 million which provides for a substantial portion of the cash proceeds from such sale to be received no later than mid-2021 with the remaining portion of cash proceeds to be received by mid-2022, subject to certain conditions. We are actively working with the buyer to potentially close the first portion of this sale before the end of 2020.

2020 BUSINESS OUTLOOK

Since the beginning of 2020, NYMEX oil prices have moved downward by over $10 per barrel (from the low $60s per barrel in early January to around $50 per barrel in mid-February 2020), due in part to concerns about the COVID-19 coronavirus and its real and potential impact on near-term worldwide oil demand. In consideration of the current oil price environment and the Company's desire to preserve ongoing liquidity, we have set our 2020 base capital budget at between $175 million and $185 million (excluding capitalized interest), which includes $10 million of capital dedicated to continuing near-term CO_2 development activities at CCA as further discussed below. This 2020 base capital budget is a $57 million (24%) reduction from our 2019 capital expenditure level. We currently anticipate that our 2020 base capital budget of $175 million to $185 million will be more than fully funded with cash flow from operations (assuming a $50 per barrel NYMEX oil price) and should result in the Company generating upwards of $100 million of cash in excess of our capital expenditures, without including any proceeds from the Pending Gulf Coast Working Interests Sale (from which we expect net proceeds of approximately $40 million) or the impact of any other potential transactions.

An additional $140 million to $150 million of capital for the CCA CO_2 tertiary flood development, most of which is scheduled to be spent in the second half of the year, is conditioned upon future Board approval. The aggregate $155 million of planned 2020 CCA tertiary-related development capital consists of $105 million for the 105-mile extension of the Greencore Pipeline to CCA, with the remainder dedicated to facilities, well work and field development. The Company currently anticipates finalizing its 2020 capital plans related to CCA during the second quarter.

Based on our capital spending plans, we currently anticipate 2020 average daily production to be between 53,000 and 56,000 BOE/d, after adjusting for the Pending Gulf Coast Working Interests Sale (see *Management's Discussion and Analysis of Financial Condition and Results of Operations – Overview – Pending Sale of Working Interests in Certain Texas Fields*). The production associated with the Pending Gulf Coast Working Interests Sale averaged 1,170 BOE/d during the fourth quarter of 2019. Our anticipated 2020 production level compares to 2019 average continuing production of 56,914 BOE/d, after reduction for 2019 property divestitures and production associated with the Pending Gulf Coast Working Interests Sale.

The Company is currently assessing various alternatives to improve the Company's balance sheet and may engage in debt reduction and/or maturity extension transactions of various types, primarily focusing on our second lien debt maturing in 2021 and 2022, plus accessing the capital markets and/or generating capital from joint ventures or asset sales. In addition, we continue to market for sale surface land with no active oil and gas operations in the Houston area and believe future land sales could generate an additional $30 million to $50 million of cash over the next few years beyond the $52 million we currently have under contract or have sold.

Denbury Resources Inc.

ESTIMATED NET QUANTITIES OF PROVED OIL AND NATURAL GAS RESERVES AND PRESENT VALUE OF ESTIMATED FUTURE NET REVENUES

Oil and Natural Gas Reserve Estimates

DeGolyer and MacNaughton ("D&M") prepared estimates of our net proved oil and natural gas reserves as of December 31, 2019, 2018 and 2017 (see the summary of D&M's report as of December 31, 2019, included as an exhibit to this Form 10-K). These estimates of reserves were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices on the first day of each month within the 12-month period in accordance with rules and regulations of the SEC. These oil and natural gas reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties.

The following table provides estimated proved reserve information prepared by D&M as of December 31, 2019, 2018 and 2017, as well as PV-10 Values and Standardized Measures for each period. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control, which are further discussed in Item 1A, *Risk Factors – Estimating our reserves, production and future net cash flows is difficult to do with any certainty*. See also *Oil and Natural Gas Operations – Field Summary Table* and *Supplemental Oil and Natural Gas Disclosures (Unaudited)* to the Consolidated Financial Statements for further discussion of reserve inputs and changes between periods.

	December 31,		
	2019	2018	2017
Estimated proved reserves			
Oil (MBbls)	226,133	255,042	252,625
Natural gas (MMcf)	24,334	43,008	42,721
Oil equivalent (MBOE)	230,189	262,210	259,745
Reserve volumes categories			
Proved developed producing			
Oil (MBbls)	178,538	200,852	189,166
Natural gas (MMcf)	21,627	39,562	38,184
Oil equivalent (MBOE)	182,143	207,446	195,530
Proved developed non-producing			
Oil (MBbls)	24,278	21,884	33,365
Natural gas (MMcf)	2,706	3,350	4,251
Oil equivalent (MBOE)	24,729	22,442	34,073
Proved undeveloped			
Oil (MBbls)	23,317	32,306	30,094
Natural gas (MMcf)	1	96	286
Oil equivalent (MBOE)	23,317	32,322	30,142
Percentage of total MBOE			
Proved developed producing	79%	79%	75%
Proved developed non-producing	11%	9%	13%
Proved undeveloped	10%	12%	12%
Representative oil and natural gas prices(1)			
Oil (NYMEX price per Bbl)	$ 55.69	$ 65.56	$ 51.34
Natural gas (Henry Hub price per MMBtu)	2.58	3.10	2.98
Present values (in thousands)(2)			
Discounted estimated future net cash flows before income taxes (PV-10 Value)(3)	$ 2,615,668	$ 4,025,139	$ 2,533,798
Standardized measure of discounted estimated future net cash flows after income taxes ("Standardized Measure")	$ 2,261,039	$ 3,351,385	$ 2,232,429

(1) The reference prices were based on the arithmetic average of the first-day-of-the-month NYMEX commodity prices for each month during the respective year. These prices do not reflect adjustments for market differentials by field that are utilized in the preparation of our reserve report to arrive at the appropriate net price we receive. See Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Operating Results Table* for details of oil and natural gas prices received, both including and excluding the impact of derivative settlements.

(2) Determined based on the average first-day-of-the-month prices for each month, adjusted to prices received by field in accordance with standards set forth in the Financial Accounting Standards Board Codification ("FASC"). PV-10 Values and the Standardized Measure are significantly impacted by the oil prices we receive relative to NYMEX oil prices (our NYMEX oil price differential). The weighted-average oil price differentials utilized were \$0.14 per Bbl below representative NYMEX oil prices as of December 31, 2019, compared to \$0.24 per Bbl below NYMEX oil prices as of December 31, 2018, and \$2.25 per Bbl below NYMEX oil prices as of December 31, 2017.

(3) PV-10 Value is a non-GAAP measure and is different from the Standardized Measure in that PV-10 Value is a pre-tax number and the Standardized Measure is an after-tax number. See *Non-GAAP Financial Measures and Reconciliations* for further discussion.

Our proved developed non-producing reserves primarily consist of (1) reserves within a proved tertiary flood in areas that have not yet experienced a response from CO_2 injection, (2) reserves that will be recovered from currently productive zones utilizing minor modifications to manage the flow of CO_2 or water within the reservoir, and (3) reserves that will be recovered through recompletions to other intervals above or below the currently producing interval.

As of December 31, 2019, our estimated proved undeveloped reserves totaled approximately 23.3 MMBOE, or approximately 10% of our estimated total proved reserves. Approximately 85% (19.8 MMBOE) of our proved undeveloped oil reserves relate to planned future development within our CO_2 tertiary operating fields. We generally consider the CO_2 tertiary proved undeveloped reserves to be lower risk than other proved undeveloped reserves that require drilling at locations offsetting existing production, because all of these proved undeveloped reserves are associated with tertiary recovery operations in fields and reservoirs that historically produced substantial volumes of oil under primary production. As of December 31, 2019, 16.1 MMBOE of our total proved undeveloped reserves are not scheduled to be developed within five years of initial booking, all of which are part of CO_2 EOR projects. We believe these reserves satisfy the conditions to be included as proved reserves because (1) we have established and continue to follow the previously adopted development plan for each of these projects; (2) we have significant ongoing development activities in each of these CO_2 EOR projects and (3) we have a historical record of completing the development of comparable long-term projects.

Our proved undeveloped reserves at December 31, 2019 were 9.0 MMBOE (28%) lower than at December 31, 2018. During 2019, we spent approximately \$50 million to convert 9.5 MMBOE of proved undeveloped reserves to proved developed reserves, primarily related to continued tertiary development activities at Bell Creek and East Heidelberg fields. Other changes in proved undeveloped reserves during 2019 included adding an additional 2.7 MMBOE primarily related to our tertiary operations at Oyster Bayou and Brookhaven fields and recognizing net downward revisions of our proved undeveloped reserves of 2.2 MMBOE, primarily the result of reserves that were reclassified to unproved based on changes in our waterflood development plans that would now extend beyond the five-year development timeframe.

During 2019, we provided oil and natural gas reserve estimates for 2018 to the United States Energy Information Agency that were substantially the same as the reserve estimates included in our Form 10-K for the year ended December 31, 2018.

Internal Controls Over Reserve Estimates

Reserve information in this report is based on estimates prepared by D&M, an independent petroleum engineering consulting firm located in Dallas, Texas, utilizing data provided by our internal reservoir engineering team and is the responsibility of management. We rely on D&M's expertise to ensure that our reserve estimates are prepared in compliance with SEC rules and regulations and that appropriate geologic, petroleum engineering, and evaluation principles and techniques are applied in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)". The person responsible for the preparation of the reserve report is a Senior Vice President at D&M; he is a Registered Professional Engineer in the State of Texas. He received a Master of Science degree in Petroleum Engineering from the University of Texas in 1984, and he has in excess of 35 years of experience in oil and gas reservoir studies and evaluations. Our Senior Vice President – Business Development and Technology is primarily responsible for overseeing the independent petroleum engineering firm during the process. Our Senior Vice President – Business Development and Technology has a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines and over 35 years of industry experience working with petroleum engineering and reserve estimates. D&M relies on various data provided by our internal reservoir engineering team in preparing its reserve estimates, including such items as oil and natural gas prices, ownership interests, production information, operating costs, planned capital expenditures and other technical data. Our internal reservoir engineering team consists of qualified petroleum engineers who maintain the Company's internal evaluation of reserves and compare the Company's information to the reserves prepared by D&M. Management is responsible for designing the internal control procedures used in the preparation of our oil and gas reserves, which include verification of data input into reserve forecasting and economics evaluation software, as well as multi-discipline management reviews. The internal reservoir engineering team reports directly to our Senior Vice President – Business Development and Technology. In addition, our Board of Directors' Reserves and Health, Safety and Environmental ("HSE") Committee, on behalf of the Board of Directors, oversees the qualifications, independence, performance and hiring of our independent petroleum engineering firm and reviews the final report and subsequent reporting of our oil and natural gas reserve estimates. The Chairman of the Reserves and HSE Committee holds a Ph.D. in Chemical Engineering from the Massachusetts Institute of Technology and bachelor's degrees in Chemistry and Mathematics from Capital University in Ohio. He has more than 35 years of industry experience, with responsibilities including reserves preparation and approval.

OIL AND NATURAL GAS OPERATIONS

Summary. Our oil and natural gas properties are concentrated in the Gulf Coast and Rocky Mountain regions of the United States. Currently our properties with proved and producing reserves in the Gulf Coast region are situated in Mississippi, Texas, and Louisiana, and in the Rocky Mountain region are situated in Montana, North Dakota and Wyoming. Our primary focus is increasing the value of our properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to CO_2 EOR operations. Our current portfolio of CO_2 EOR projects provides us significant oil production and reserve growth potential in the future, assuming crude oil prices are at levels that support the development of those projects.

We have been conducting and expanding EOR operations on our assets in the Gulf Coast region since 1999, and as a result, we currently have many more CO_2 EOR projects in this region than in the Rocky Mountain region. We began operations in the Rocky Mountain region in 2010 in connection with, and following, our merger with Encore Acquisition Company ("Encore"). In 2012, as part of a significant sale and exchange transaction with Exxon Mobil Corporation ("ExxonMobil"), we sold to ExxonMobil our Bakken area assets in North Dakota and Montana in exchange for (1) $1.3 billion in cash, (2) operating interests in Hartzog Draw and Webster fields in Wyoming and Texas, respectively, and (3) an overriding royalty interest equivalent to an approximate one-third ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field in Wyoming (the "Bakken Exchange Transaction"). In the Gulf Coast region, we own what is, to our knowledge, the region's only significant naturally occurring source of CO_2, and these large volumes of naturally occurring CO_2 give us a significant competitive advantage in this area. In addition to this naturally occurring CO_2 source, we utilize CO_2 captured from industrial sources which would otherwise be released into the atmosphere (sometimes referred to as anthropogenic, man-made or industrial-source CO_2) in our tertiary operations, including CO_2 from the LaBarge Field in Wyoming, which is captured in conjunction with processing helium from the LaBarge Field gas stream at ExxonMobil's Shute Creek gas plant. These industrial sources of CO_2 help us recover additional oil from mature oil fields and, we believe, also provide an economical way to reduce atmospheric CO_2 emissions through the associated underground storage of CO_2 which incidentally occurs as part of our oil-producing EOR operations.

Denbury Resources Inc.

Field Summary Table. The following table provides a summary by field and region of selected proved oil and natural gas reserve information, including total proved reserve quantities as of December 31, 2019, and average daily production for 2019, all based on Denbury's net revenue interest ("NRI"). The reserve estimates presented were prepared by D&M, independent petroleum engineers located in Dallas, Texas. We serve as operator of nearly all of our significant properties, in which we also own most of the interests, although typically less than a 100% working interest, and a lesser NRI due to royalties and other burdens. For additional oil and natural gas reserves information, see *Estimated Net Quantities of Proved Oil and Natural Gas Reserves and Present Value of Estimated Future Net Revenues* above and *Supplemental Oil and Natural Gas Disclosures (Unaudited)* to the Consolidated Financial Statements.

	Proved Reserves as of December 31, 2019(1)				2019 Average Daily Production		
	Oil (MBbls)	Natural Gas (MMcf)	MBOEs	% of Company Total MBOEs	Oil (Bbls/d)	Natural Gas (Mcf/d)	Average 2019 NRI
Tertiary oil and gas properties							
Gulf Coast region							
Delhi	14,565	—	14,565	6.3%	4,324	—	58.1%
Hastings	31,641	—	31,641	13.7%	5,403	—	79.9%
Heidelberg	20,792	—	20,792	9.0%	4,195	—	81.3%
Oyster Bayou	16,965	—	16,965	7.4%	4,345	—	87.3%
Tinsley	15,553	—	15,553	6.8%	4,608	—	82.2%
West Yellow Creek	1,318	—	1,318	0.6%	640	—	42.5%
Mature properties(2)	16,745	—	16,745	7.3%	6,422	—	80.2%
Total Gulf Coast region	117,579	—	117,579	51.1%	29,937	—	76.4%
Rocky Mountain region							
Bell Creek	13,523	—	13,523	5.9%	5,228	—	84.9%
Salt Creek	6,158	—	6,158	2.7%	2,143	—	19.0%
Grieve	977	—	977	0.4%	53	—	20.5%
Total Rocky Mountain region	20,658	—	20,658	9.0%	7,424	—	42.1%
Total tertiary properties	138,237	—	138,237	60.1%	37,361	—	66.4%
Non-tertiary oil and gas properties							
Gulf Coast region							
Texas(3)	17,151	7,180	18,348	8.0%	3,865	2,672	81.4%
Mississippi and other	1,733	3,523	2,320	1.0%	609	2,203	13.5%
Total Gulf Coast region	18,884	10,703	20,668	9.0%	4,474	4,875	47.2%
Rocky Mountain region							
Cedar Creek Anticline(4)	67,003	10,077	68,683	29.8%	13,818	1,632	80.1%
Other	2,009	3,554	2,601	1.1%	805	2,739	62.2%
Total Rocky Mountain region	69,012	13,631	71,284	30.9%	14,623	4,371	78.8%
Total non-tertiary properties	87,896	24,334	91,952	39.9%	19,097	9,246	67.0%
Total continuing properties	226,133	24,334	230,189	100.0%	56,458	9,246	66.6%
Property sales							
Property divestitures(5)	—	—	—	—%	214	—	64.2%
Company Total	226,133	24,334	230,189	100.0%	56,672	9,246	66.6%

(1) Reserve estimates were prepared in accordance with FASC Topic 932, *Extractive Industries – Oil and Gas*, using the arithmetic averages of the first-day-of-the-month NYMEX commodity price for each month during 2019, which were $55.69 per Bbl for crude oil and $2.58 per MMBtu for natural gas.

(2) Mature properties include Brookhaven, Cranfield, Eucutta, Little Creek, Mallalieu, Martinville, McComb and Soso fields in Mississippi.

(3) Texas non-tertiary production includes production associated with the Pending Gulf Coast Working Interests Sale (see *Management's Discussion and Analysis of Financial Condition and Results of Operations – Overview – Pending Sale of Working Interests in Certain Texas Fields)*.

(4) The Cedar Creek Anticline consists of a series of 13 different operating areas.

(5) Includes production from Citronelle Field sold in July 2019.

Enhanced Oil Recovery Overview. CO_2 used in EOR is one of the most efficient tertiary recovery mechanisms for producing crude oil. When injected under pressure into underground, oil-bearing rock formations, CO_2 acts somewhat like a solvent as it travels through the reservoir rock, mixing with and modifying the characteristics of the oil so it can be produced and sold. The terms "tertiary flood," "CO_2 flood" and "CO_2 EOR" are used interchangeably throughout this document.

While enhanced oil recovery projects utilizing CO_2 have been successfully performed by numerous oil and gas companies in a wide range of oil-bearing reservoirs in different oil-producing basins, we believe our investments, experience and acquired knowledge give us a strategic and competitive advantage in the areas in which we operate. We apply what we have learned and developed over the years to improve and increase sweep efficiency within the CO_2 EOR projects we operate.

We began our CO_2 operations in August 1999, when we acquired Little Creek Field, followed by our acquisition of Jackson Dome CO_2 reserves and the NEJD pipeline in 2001. Based upon our success at Little Creek and the ownership of the CO_2 reserves, we began to transition our capital spending and acquisition efforts to focus more heavily on CO_2 EOR and, over time, transformed our strategy to focus primarily on owning and operating oil fields that are well suited for CO_2 EOR projects. Prior to tertiary flooding, we strive to maximize the currently sizeable primary and secondary production from our prospective tertiary fields and from fields in which tertiary floods have commenced but still contain significant non-tertiary production. Our asset base today almost entirely consists of, or otherwise relates to, oil fields that we are currently flooding with CO_2 or plan to flood with CO_2 in the future, or assets that produce CO_2.

Our tertiary operations have grown so that (1) 60% of our proved reserves at December 31, 2019 are proved tertiary oil reserves; (2) 64% of our 2019 total production was related to tertiary oil operations (on a BOE basis); and (3) 63% of our 2019 capital expenditures (excluding acquisitions) were related to our tertiary oil operations. At year-end 2019, the proved oil reserves in our tertiary recovery oil fields had an estimated PV-10 Value of approximately $1.8 billion, or 69% of our total PV-10 Value. In addition, there are significant probable and possible reserves at several other fields for which tertiary operations are underway or planned.

Although the up-front cost of tertiary production infrastructure and time to construct pipelines and production facilities is greater than in primary oil recovery in most circumstances, we believe tertiary recovery has several favorable, offsetting and unique attributes, including (1) a lower exploration risk, as we are operating oil fields that have significant historical production and reservoir and geological data, (2) lower production decline rates than unconventional development, (3) reasonable return metrics at our anticipated long-term prices, (4) limited competition for this recovery method in our geographic regions and a strategic advantage due to our ownership of the CO_2 reserves and CO_2 pipeline infrastructure, (5) our EOR operations are generally less disruptive to new habitats in comparison to other oil and natural gas development because we further develop existing (as opposed to new) oil fields, and (6) through our oil-producing EOR operations, we concurrently store CO_2 captured from industrial sources in the same underground formations that previously trapped and stored oil and natural gas.

Tertiary Oil Properties

Gulf Coast Region

CO_2 Sources and Pipelines

Jackson Dome. Our primary Gulf Coast CO_2 source, Jackson Dome, located near Jackson, Mississippi, was discovered during the 1970s by oil and gas companies that were exploring for hydrocarbons. This large and relatively pure source of naturally occurring CO_2 (98% CO_2) is, to our knowledge, the only significant underground deposit of CO_2 in the United States east of the Mississippi River. Together with the related CO_2 pipeline infrastructure, Jackson Dome provides us a significant strategic advantage in the acquisition of properties in Mississippi, Louisiana and southeastern Texas that are well suited for CO_2 EOR.

We acquired Jackson Dome in February 2001 in a purchase that also gave us ownership and control of the NEJD CO_2 pipeline and provided us with a reliable supply of CO_2 at a reasonable and predictable cost for our Gulf Coast CO_2 tertiary recovery operations. Since February 2001, we have acquired and drilled numerous CO_2-producing wells, significantly increasing our estimated proved Gulf Coast CO_2 reserves from approximately 800 Bcf at the time of acquisition of Jackson Dome to approximately 4.8 Tcf as of December 31, 2019. The proved CO_2 reserve estimates are based on a gross (8/8ths) basis, of which our net revenue interest is approximately 3.8 Tcf, and is included in the evaluation of proved CO_2 reserves prepared by D&M, an independent petroleum engineering consulting firm. In discussing our available CO_2 reserves, we make reference to the gross amount of proved and probable reserves, as this is the amount that is available both for our own tertiary recovery programs and for industrial users who are customers of Denbury and others, as we are responsible for distributing the entire CO_2 production stream.

In addition to our proved reserves, we estimate that we have 910.1 Bcf, on a gross (8/8ths) basis, of probable CO_2 reserves at Jackson Dome. While the majority of these probable reserves are located in structures that have been drilled and tested, such reserves are still considered probable reserves because (1) the original well is plugged; (2) they are located in fault blocks that are immediately adjacent to fault blocks with proved reserves; or (3) they are reserves associated with increasing the ultimate recovery factor from our existing reservoirs with proved reserves. In addition, a significant portion of these probable reserves at Jackson Dome are located in undrilled structures where we have sufficient subsurface and seismic data indicating geophysical attributes that, coupled with our historically high drilling success rate, provide a reasonably high degree of certainty that CO_2 is present.

In addition to our drilling at Jackson Dome, we have the capability to expand our processing and dehydration capacities and install additional pipelines and/or pumping stations necessary to transport the CO_2 through our controlled pipeline network. We expect our current proved reserves of CO_2, coupled with a risked drilling program at Jackson Dome and CO_2 expected to be captured from industrial sources, to provide sufficient quantities of CO_2 for us to develop our proved and probable EOR reserves in the Gulf Coast region. In the future, we believe that once a CO_2 flood in a field reaches its productive economic limit, we could recycle a portion of the CO_2 that remains in that field's reservoir and utilize it for oil production in another field's tertiary flood.

In the Gulf Coast region, approximately 84% of our average daily CO_2 produced from Jackson Dome or captured from industrial sources in 2019 was used in our tertiary recovery operations, compared to 83% in 2018 and 87% in 2017, with the balance delivered to third-party industrial users. During 2019, we used an average of 511 MMcf/d of CO_2 (including CO_2 captured from industrial sources) for our tertiary activities.

Gulf Coast CO_2 Captured from Industrial Sources. In addition to our natural source of CO_2, we are currently party to two long-term contracts to purchase CO_2 from industrial plants. We have purchased CO_2 from an industrial facility in Port Arthur, Texas since 2012 and from an industrial facility in Geismar, Louisiana since 2013, which supplied an average of approximately 53 MMcf/d of CO_2 to our EOR operations during 2019. Additionally, we are in ongoing discussions with other parties regarding plans to construct plants near the Green Pipeline. In order to capture such volumes, we (or the plant owner) would need to install additional equipment, which includes, at a minimum, compression and dehydration facilities.

Gulf Coast CO_2 Pipelines. We acquired the 183-mile NEJD CO_2 pipeline that runs from Jackson Dome to near Donaldsonville, Louisiana, as part of the 2001 acquisition of our Jackson Dome CO_2 source. Since 2001, we have acquired or constructed nearly 750 miles of CO_2 pipelines, and as of December 31, 2019, we have access to nearly 925 miles of CO_2 pipelines, which gives us the ability to deliver CO_2 throughout the Gulf Coast region. In addition to the NEJD CO_2 pipeline, the major pipelines in the Gulf Coast region are the Free State Pipeline (90 miles), Delta Pipeline (110 miles), Green Pipeline Texas (120 miles), and Green Pipeline Louisiana (200 miles).

Completion of the Green Pipeline allowed for the first CO_2 injection into Hastings Field, located near Houston, Texas, in 2010, and gives us the ability to deliver CO_2 to oil fields all along the Gulf Coast from Baton Rouge, Louisiana, to Alvin, Texas. At the present time, most of the CO_2 flowing in the Green Pipeline is delivered from the Jackson Dome area, but also includes the CO_2 we are receiving from the industrial facilities in Port Arthur, Texas and Geismar, Louisiana, and we are currently transporting a third party's CO_2 for a fee to the sales point at Hastings Field. We currently have ample capacity within the Green Pipeline to handle additional volumes that may be required to develop our inventory of CO_2 EOR projects in this area.

Tertiary Properties with Tertiary Production and Proved Tertiary Reserves at December 31, 2019

Delhi Field. Delhi Field is located east of Monroe, Louisiana. In May 2006, we purchased our initial interest in Delhi for $50 million. We began well and facility development in 2008, began delivering CO_2 to the field in 2009 via the Delta Pipeline, which runs from Tinsley Field to Delhi Field, and first tertiary production occurred at Delhi Field in 2010. During 2016, we completed construction of a natural gas liquids extraction plant, which provides us with the ability to sell natural gas liquids from the produced stream, improve the efficiency of the CO_2 flood, and utilize extracted methane to power the plant and reduce field operating expenses. Production from Delhi Field in the fourth quarter of 2019 averaged 4,085 Bbls/d, compared to 4,526 Bbls/d in the fourth quarter of 2018. During 2020, we plan to perform conformance work at Delhi Field.

Hastings Field. Hastings Field is located south of Houston, Texas. We acquired a majority interest in this field in February 2009 for $247 million. We initiated CO_2 injection in the West Hastings Unit during 2010 upon completion of the construction of the Green Pipeline. Due to the large vertical oil column that exists in the field, we are developing the Frio reservoir using dedicated CO_2 injection and producing wells for each of the major sand intervals. We began producing oil from our EOR operations at Hastings Field in 2012, and we booked initial proved tertiary reserves for the West Hastings Unit in 2012. The Company also has future plans for continued tertiary development of existing proved undeveloped reserves at the field. During the fourth quarter of 2019, tertiary production from Hastings Field averaged 5,097 Bbls/d, compared to 5,480 Bbls/d in the fourth quarter of 2018.

Heidelberg Field. Heidelberg Field is located in Mississippi off of the Free State Pipeline and consists of an East Unit and a West Unit. Construction of the CO_2 facility, connecting pipeline and well work commenced on the West Heidelberg Unit during 2008, with our first CO_2 injections into the Eutaw zone. Our first tertiary oil production occurred in 2009, and we began flooding the Christmas and Tuscaloosa zones in 2013 and 2014, respectively. During 2019, we expanded our tertiary flood of the Christmas zone and invested in non-tertiary behind pipe projects. During the fourth quarter of 2019, tertiary production at Heidelberg Field averaged 4,409 Bbls/d, compared to 4,269 Bbls/d in the fourth quarter of 2018. Our 2020 development plans for Heidelberg Field include conformance work, with future plans for continued tertiary development of existing proved undeveloped reserves at the field.

Oyster Bayou Field. We acquired a majority interest in Oyster Bayou Field in 2007. The field is located in southeast Texas, east of Galveston Bay, and is somewhat unique when compared to our other CO_2 EOR projects because the field covers a relatively small area of 3,912 acres. We began CO_2 injections into Oyster Bayou Field in 2010, commenced tertiary production in 2011 from the Frio A-1 zone, and booked initial proved tertiary reserves for the field in 2012. In 2014, we completed development of the Frio A-2 zone. During the fourth quarter of 2019, tertiary production at Oyster Bayou Field averaged 4,261 Bbls/d, compared to 4,785 Bbls/d in the fourth quarter of 2018. During 2020, we plan to invest in down-dip expansion of the Frio A-2 zone.

Tinsley Field. We acquired Tinsley Field in 2006. This Mississippi field was discovered and first developed in the 1930s and is separated by different fault blocks. As is the case with the majority of fields in Mississippi, Tinsley Field produces from multiple reservoirs. Our CO_2 enhanced oil recovery operations at Tinsley Field have thus far targeted the Woodruff formation, although there is additional potential in the Perry sandstone and other smaller reservoirs. We commenced tertiary oil production from Tinsley Field in 2008 and substantially completed development of the Woodruff formation during 2014. During the fourth quarter of 2019, tertiary oil production from the field averaged 4,343 Bbls/d, compared to 5,033 Bbls/d in the fourth quarter of 2018. Although production from Tinsley Field is believed to have peaked in 2015 and is generally on decline, we continue to evaluate future potential investment opportunities in this field.

In addition to our tertiary operations at Tinsley Field, during 2018 and 2019, we conducted exploitation drilling in other oil-bearing formations in the field, and we continue to evaluate exploitation opportunities in additional horizons underlying the existing CO_2 EOR flood.

West Yellow Creek Field. We acquired an approximate 48% non-operated working interest in West Yellow Creek Field in Mississippi in March 2017 for approximately $16 million, a field in which the operator had previously invested significant capital converting the field to a CO_2 EOR flood. Under our arrangement with the operator, we supply CO_2 to the field for a fee. West Yellow Creek Field is in close proximity and analogous to Eucutta Field, a very successful CO_2 flood that we developed and continue to operate. We booked initial proved tertiary oil reserves at West Yellow Creek Field as of year-end 2017 and commenced tertiary production in early 2018. During the fourth quarter of 2019, tertiary oil production from the field averaged 807 Bbls/d compared to 375 Bbls/d in the fourth quarter of 2018. Development of the field is ongoing, with future plans for continued tertiary development of the initial formation within the field.

Mature properties. Mature properties include our longest-producing properties which are generally located along our NEJD CO_2 pipeline in southwest Mississippi and Louisiana and our Free State Pipeline in east Mississippi. This group of properties includes our initial CO_2 field, Little Creek, as well as several other fields (Brookhaven, Cranfield, Eucutta, Mallalieu, Martinville, McComb and Soso fields). These fields accounted for 17% of our total 2019 CO_2 EOR production and approximately 7% of our year-end proved reserves. These fields have been producing under CO_2 flood for many years, in many cases more than a decade, and their production is generally declining, though we continue to evaluate future potential investment opportunities in these fields.

Future Tertiary Properties with No Tertiary Production or Proved Tertiary Reserves at December 31, 2019

Pending Sale of Working Interests in Certain Texas Fields. In December 2019, we entered into a definitive agreement to sell half of our nearly 100% working interest positions in four conventional southeast Texas oil fields (consisting of Webster, Thompson, Manvel and East Hastings) for $50 million cash and a carried interest in ten wells to be drilled by the purchaser. The sale is currently expected to occur in early March 2020. Under the agreement, the purchaser is committed to funding 100% of the capital required to drill and complete an initial ten horizontal wells across the fields, with the first of the ten wells to be spud within six months of closing and with all ten wells to be completed within 18 months after closing. On these initial ten wells, Denbury will receive a 6.25% overriding royalty interest prior to the combined payout of the wells in a specified field and subsequent to payout, Denbury will receive production revenues from, and bear the cost of, its 50% working interest in each well. As part of the agreement, we will retain 100% ownership of the future Webster Unit CO_2 flood, wherein (1) the purchaser may elect to participate in the future CO_2 flood through reimbursement to Denbury of the purchaser's working interest share of project costs incurred to date, or (2) if the purchaser declines to participate in the CO_2 flood, we have the right to repurchase the purchaser's working interest in Webster Field under a contractually agreed valuation mechanism.

Webster Field. We acquired our interest in Webster Field in 2012 as part of the Bakken Exchange Transaction. The field is located southeast of Houston, Texas, approximately eight miles northeast of our Hastings Field which we are currently flooding with CO_2. At December 31, 2019, Webster Field had estimated proved non-tertiary reserves of approximately 3.2 MMBOE, net to our interest, all of which are proved developed. During the fourth quarter of 2019, non-tertiary production at Webster Field, including production related to the Pending Gulf Coast Working Interests Sale (see *Pending Sale of Working Interests in Certain Texas Fields* above*),* averaged 923 BOE/d, compared to 841 BOE/d in the fourth quarter of 2018. Webster Field is geologically similar to our Hastings Field, producing oil from the Frio zone at similar depths; as a result, we believe it is well suited for CO_2 EOR. In 2014, we completed a nine-mile lateral between the Green Pipeline and Webster Field, which we plan will eventually deliver CO_2 to the field. The timing of the development of a CO_2 flood at Webster Field is primarily dependent upon capital availability and priorities and future oil prices.

Conroe Field. Conroe Field, our largest potential tertiary flood in the Gulf Coast region, is located north of Houston, Texas. We acquired a majority interest in this field in 2009 for $271 million in cash and 11.6 million shares of Denbury common stock, for a total aggregate value of $439 million. Conroe Field had estimated proved non-tertiary reserves of approximately 9.5 MMBOE at December 31, 2019, net to our interest, all of which are proved developed. During the fourth quarter of 2019, non-tertiary production at Conroe Field averaged 1,861 BOE/d, compared to 1,970 BOE/d in the fourth quarter of 2018.

To initiate a CO_2 flood at Conroe Field, a pipeline must be constructed so that CO_2 can be delivered to the field. This pipeline, which is planned as an extension of our Green Pipeline, is preliminarily estimated to cover approximately 90 miles at a cost of approximately $220 million. Our current plan for initiating a CO_2 flood at Conroe Field is scheduled several years from now, the timing of which may change depending on capital availability and priorities, future oil prices and pipeline construction.

In addition to the currently-producing oil-bearing formations at Conroe Field, we are evaluating exploitation opportunities in other formations. We currently do not have any additional wells planned for 2020 but continue to evaluate additional opportunities and plan to de-risk other areas of the field in the future.

Thompson Field. We acquired our interest in Thompson Field in June 2012 for $366 million. The field is located in Texas, approximately 18 miles west of our Hastings Field. Thompson Field had estimated proved non-tertiary reserves of approximately 4.3 MMBOE at December 31, 2019, net to our interest, all of which are proved developed. During the fourth quarter of 2019, non-tertiary production at Thompson Field, including production related to the Pending Gulf Coast Working Interests Sale (see *Pending Sale of Working Interests in Certain Texas Fields* above*),* averaged 1,008 BOE/d, compared to 942 BOE/d in the fourth quarter of 2018. Thompson Field is geologically similar to Hastings Field, producing oil from the Frio zone at similar depths, and we therefore believe it has CO_2 EOR potential. Under the terms of the Thompson Field acquisition agreement, after the initiation of CO_2 injection, the seller will retain approximately a 5% gross revenue interest (less severance taxes) once average monthly oil production exceeds 3,000 Bbls/d. The timing of the development of a CO_2 flood at Thompson Field is primarily dependent upon capital availability and priorities and future oil prices.

Rocky Mountain Region

CO_2 Sources and Pipelines

LaBarge Field. We acquired an overriding royalty interest equivalent to an approximate one-third ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field in the fourth quarter of 2012 as part of the Bakken Exchange Transaction. LaBarge Field is located in southwestern Wyoming, and as of December 31, 2019, our interest in LaBarge Field consisted of approximately 1.1 Tcf of proved CO_2 reserves.

During 2019, we received an average of approximately 97 MMcf/d of CO_2 from the Shute Creek gas processing plant at LaBarge Field that we used in our Rocky Mountain region CO_2 floods. Based on current capacity, and subject to availability of CO_2, we currently expect our CO_2 volumes from Shute Creek to increase in future years. We pay ExxonMobil a fee to process and deliver the CO_2, which we use in our Rocky Mountain region CO_2 floods.

Other Rocky Mountain CO_2 Sources. We currently receive all of the CO_2 from the ConocoPhillips-operated Lost Cabin gas plant in central Wyoming, which we currently expect to provide us as much as 30 MMcf/d of CO_2 for use in our Rocky Mountain region CO_2 floods. We currently estimate that our existing CO_2 sources, plus additional CO_2 from those or other CO_2 sources in the region, are sufficient to carry out our base Rocky Mountain region EOR development plans.

Rocky Mountain CO_2 Pipelines. The 20-inch Greencore Pipeline in Wyoming is the first CO_2 pipeline we constructed in the Rocky Mountain region. We plan to use the pipeline as our trunk line in the Rocky Mountain region, eventually connecting our various Rocky Mountain region CO_2 sources to the Cedar Creek Anticline in eastern Montana and western North Dakota. The 232-mile pipeline begins at the ConocoPhillips-operated Lost Cabin gas plant in Wyoming and terminates at Bell Creek Field in Montana. We completed construction of the pipeline in 2012 and received our first CO_2 deliveries from the ConocoPhillips-operated Lost Cabin gas plant during 2013. During 2014, we completed construction of an interconnect between our Greencore Pipeline and an existing third-party CO_2 pipeline in Wyoming, which enables us to transport CO_2 from LaBarge Field to our Bell Creek Field.

In mid-2018, we sanctioned the CO_2 enhanced oil recovery development project at Cedar Creek Anticline, which requires a 105-mile extension of the Greencore CO_2 pipeline to CCA from Bell Creek Field. The capital outlay for the pipeline is projected to be approximately \$150 million, of which we have incurred approximately \$45 million through December 31, 2019 (see also *Cedar Creek Anticline CO_2 EOR Project* below for further discussion).

Tertiary Properties with Tertiary Production and Proved Tertiary Reserves at December 31, 2019

Bell Creek Field. We acquired our interest in Bell Creek Field in southeast Montana as part of the Encore merger in 2010. The oil-producing reservoir in Bell Creek Field is a sandstone reservoir with characteristics similar to those we have successfully flooded with CO_2 in the Gulf Coast region. During 2013, we began first CO_2 injections into Bell Creek Field, recorded our first tertiary oil production, and booked initial proved tertiary reserves. Tertiary production during the fourth quarter of 2019 averaged 5,618 Bbls/d of oil, compared to 4,421 Bbls/d in the fourth quarter of 2018. During 2018, we completed the phase five expansion at the field, and in April 2019 commenced CO_2 injection into phase six of the field development. The initial production response from the phase six expansion of the flood occurred in early 2020, though production will slowly ramp up during 2020 as additional wells begin to respond.

Grieve Field. Under a 2011 farm-in agreement, we obtained a 65% working interest in Grieve Field, located in Natrona County, Wyoming, in exchange for developing the Grieve Field CO_2 flood. During 2016, the Company and its joint venture partner in Grieve Field revised their development arrangement for the field so that our partner funded \$55 million of the remaining estimated capital to complete development of the facility and fieldwork in exchange for a 14% higher working interest and a disproportionate sharing of revenue from the first 2 million barrels of production. Thus, our working interest in the field was reduced from 65% to 51%, and our net revenue interest on the first million barrels of production is approximately 20%. We commenced tertiary production from Grieve Field during the fourth quarter of 2018 and booked initial proved tertiary reserves during 2019. Tertiary production during the fourth quarter of 2019 averaged 60 Bbls/d of oil, compared to 20 Bbls/d in the fourth quarter of 2018.

Salt Creek Field. We acquired our 23% non-operated working interest in Salt Creek Field in Wyoming for approximately \$72 million in June 2017. Tertiary production during the fourth quarter of 2019 averaged 2,223 Bbls/d of oil, compared to 2,107 Bbls/d in the fourth quarter of 2018.

Future Tertiary Properties with No Tertiary Production or Proved Tertiary Reserves at December 31, 2019

Cedar Creek Anticline. CCA is the largest potential EOR property that we own and currently our largest producing property, contributing approximately 24% of our 2019 total production. Historical production from the property has primarily been from the Red River interval. The field is primarily located in Montana but extends over such a large area (approximately 126 miles) that it also extends into North Dakota. CCA is a series of 13 different operating areas on a common geological trend, each of which could be considered a field by itself. We acquired our initial interest in CCA as part of the Encore merger in 2010 and acquired additional interests from a wholly-owned subsidiary of ConocoPhillips in 2013 for $1.0 billion, adding 42.2 MMBOE of incremental proved reserves at that date. Production from CCA averaged 13,730 BOE/d during the fourth quarter of 2019, compared to production during the fourth quarter of 2018 of 14,961 BOE/d. The non-tertiary proved reserves associated with CCA were 68.7 MMBOE, net to our interest, as of December 31, 2019.

In addition to the Red River interval, CCA contains other oil-bearing intervals including Mission Canyon and Charles B. We began pursuing these additional exploitation opportunities in late 2017. We have drilled nine successful Mission Canyon exploitation wells and a successful initial test well in Cabin Creek's Charles B formation over the last few years. We continue to evaluate the Charles B formation and believe it has characteristics that would make it a good candidate for secondary or tertiary flooding.

Cedar Creek Anticline CO_2 EOR Project. CCA is located approximately 110 miles north of Bell Creek Field, and our current plan is to connect this field to our Greencore Pipeline by the end of 2020. In June 2018, we announced the sanctioning of the CO_2 enhanced oil recovery development project at Cedar Creek Anticline. The estimated capital outlay to first tertiary production includes $150 million for a 105-mile extension of the Greencore CO_2 pipeline from Bell Creek Field discussed above and an additional $150 million for facilities, well work and field development in the Red River formation at East Lookout Butte and Cedar Hills South fields in CCA. Approximately $50 million has been incurred through December 31, 2019, primarily related to purchase of pipe for the planned CO_2 pipeline extension. First tertiary production is currently expected in the second half of 2022 or early 2023, with additional phases of development expected to target the Interlake, Stony Mountain and Red River formations at Cabin Creek Field. In light of the current oil price environment and the Company's desire to preserve ongoing liquidity, the Company is continuing to evaluate the CCA tertiary development timeline, and in particular the construction of the pipeline in 2020, and currently anticipates finalizing its plans in the second quarter of 2020. See further discussion of the Company's 2020 capital plans at *Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – 2020 Capital Budget*.

Hartzog Draw Field. We acquired our interest in Hartzog Draw Field in 2012 as part of the Bakken Exchange Transaction. The field is located in the Powder River Basin of northeastern Wyoming, approximately 12 miles from our Greencore Pipeline. Hartzog Draw Field had estimated proved reserves of approximately 2.6 MMBOE at December 31, 2019, net to our interest, 0.6 MMBOE of which relate to the natural gas producing Big George coal zone. During the fourth quarter of 2019, non-tertiary production averaged 1,172 BOE/d, compared to 1,327 BOE/d in the fourth quarter of 2018. Industry activity around this field has been increasing for the last several years, with several operators testing various formations such as the Turner, Niobrara, Shannon, Parkman and Mowry for potential development. We believe the oil reservoir characteristics of Hartzog Draw Field make it well suited for CO_2 EOR in the future. The timing of development of a CO_2 flood at Hartzog Draw Field is primarily dependent upon capital availability and priorities and future oil prices.

Other Non-Tertiary Oil Properties

Despite the majority of our oil and natural gas properties discussed above consisting of either existing or planned future tertiary floods, we also produce oil and natural gas either from fields in both our Gulf Coast and Rocky Mountain regions that are not amenable to EOR or from specific reservoirs (within an existing tertiary field) that are not amenable to EOR. For example, at Heidelberg Field, we produce natural gas from the Selma Chalk reservoir, which is separate from the Christmas and Eutaw reservoirs currently being flooded with CO_2. Continuing production from these other non-tertiary properties totaled 1,567 BOE/d during the fourth quarter of 2019, compared to 1,611 BOE/d during the fourth quarter of 2018.

OIL AND GAS ACREAGE, PRODUCTIVE WELLS AND DRILLING ACTIVITY

In the data below, “gross” represents the total acres or wells in which we own a working interest and “net” represents the gross acres or wells multiplied by our working interest percentage. For the wells that produce both oil and gas, the well is typically classified as an oil or natural gas well based on the ratio of oil to natural gas production.

Oil and Gas Acreage

The following table sets forth our acreage position at December 31, 2019:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast region	188,770	155,270	286,922	18,374	475,692	173,644
Rocky Mountain region	362,327	315,029	122,321	22,969	484,648	337,998
Total	551,097	470,299	409,243	41,343	960,340	511,642

The percentage of our net undeveloped acreage that is subject to expiration over the next three years, if not renewed, is approximately 4% in 2020, 11% in 2021 and 7% in 2022.

Productive Wells

The following table sets forth our gross and net productive oil and natural gas wells as of December 31, 2019:

	Producing Oil Wells		Producing Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated wells						
Gulf Coast region	1,111	1,045	128	120	1,239	1,165
Rocky Mountain region	965	919	268	174	1,233	1,093
Total	2,076	1,964	396	294	2,472	2,258
Non-operated wells						
Gulf Coast region	43	18	—	—	43	18
Rocky Mountain region	591	132	2	1	593	133
Total	634	150	2	1	636	151
Total wells						
Gulf Coast region	1,154	1,063	128	120	1,282	1,183
Rocky Mountain region	1,556	1,051	270	175	1,826	1,226
Total	2,710	2,114	398	295	3,108	2,409

Denbury Resources Inc.

Drilling Activity

The following table sets forth the results of our drilling activities over the last three years. As of December 31, 2019, we did not have any wells in progress.

	Year Ended December 31,					
	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells(1)						
Productive(2)	1	1	2	2	—	—
Non-productive(3)	—	—	—	—	—	—
Development wells(1)						
Productive(2)	19	18	14	12	2	2
Non-productive(3)(4)	—	—	3	3	—	—
Total	20	19	19	17	2	2

(1) An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well. A development well is a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(2) A productive well is an exploratory or development well drilled and completed during the year and found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

(3) A non-productive well is an exploratory or development well that is not a productive well.

(4) During 2019, 2018 and 2017, an additional 7, 4 and 3 wells, respectively, were drilled for water or CO_2 injection purposes.

The following table summarizes sales volumes, sales prices and production cost information for our net oil and natural gas production for the years ended December 31, 2019, 2018 and 2017:

	Year Ended December 31,		
	2019	2018	2017
Net sales volume			
Gulf Coast region			
Oil (MBbls)	12,638	13,484	14,114
Natural gas (MMcf)	1,779	1,973	1,995
Total Gulf Coast region (MBOE)	12,935	13,813	14,447
Rocky Mountain region			
Oil (MBbls)	8,047	7,880	7,205
Natural gas (MMcf)	1,595	1,988	2,141
Total Rocky Mountain region (MBOE)	8,313	8,211	7,562
Total Company (MBOE)	21,248	22,024	22,009
Average sales prices – excluding impact of derivative settlements			
Gulf Coast region			
Oil (per Bbl)	$ 60.32	$ 67.75	$ 51.19
Natural gas (per Mcf)	2.49	3.16	2.98
Rocky Mountain region			
Oil (per Bbl)	$ 55.02	$ 63.30	$ 49.58
Natural gas (per Mcf)	1.57	2.01	1.88
Total Company			
Oil (per Bbl)	$ 58.26	$ 66.11	$ 50.64
Natural gas (per Mcf)	2.06	2.58	2.41
Average production cost (per BOE sold)[(1)]			
Gulf Coast region	$ 22.49	$ 22.22	$ 20.48
Rocky Mountain region	22.40	22.27	20.09
Total Company	22.46	22.24	20.35

(1) Excludes oil and natural gas ad valorem and production taxes.

PRODUCTION AND UNIT PRICES

Further information regarding average production rates, unit sales prices and unit costs per BOE are set forth under Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Operating Results Table*, included herein.

TITLE TO PROPERTIES

As is customary in the oil and natural gas industry, Denbury conducts a limited title examination at the time of its acquisition of properties or leasehold interests targeted for enhanced recovery, and curative work is performed with respect to significant defects on higher-value properties of the greatest significance. We believe that title to our oil and natural gas properties is good and defensible, subject only to such exceptions that we believe do not materially interfere with the use of such properties, including encumbrances, easements, restrictions and royalty, overriding royalty and other similar interests.

SIGNIFICANT OIL AND GAS PURCHASERS AND PRODUCT MARKETING

Oil and natural gas sales are made on a day-to-day basis or under short-term contracts at the current area market price. We would not expect the loss of any single purchaser to have a material adverse effect upon our operations; however, the loss of a large single purchaser could potentially reduce the competition for our oil and natural gas production, which in turn could negatively impact the prices we receive. For the year ended December 31, 2019, three purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (32%), Hunt Crude Oil Supply Company (11%) and Sunoco Inc. (11%). For the year ended December 31, 2018, two purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (24%) and Hunt Crude Oil Supply Company (10%). For the year ended December 31, 2017, two purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (22%) and Marathon Petroleum Company (10%).

Our ability to market oil and natural gas depends on many factors beyond our control, including the extent of domestic production and imports of oil and natural gas, the proximity of our oil and natural gas production to pipelines and corresponding markets, the available capacity in such pipelines, the demand for oil and natural gas, the effects of weather, and the effects of state and federal regulation. As of December 31, 2019, we have not experienced significant difficulty in finding a market for all of our production as it becomes available or in transporting our production to those markets; however, there is no assurance that we will always be able to market all of our production or obtain favorable prices.

Oil Marketing

Prices received in a regional market fluctuate frequently and can differ from NYMEX pricing due to a variety of reasons, including supply and/or demand factors, crude oil quality and location differentials. The oil differentials we received in the Gulf Coast and Rocky Mountain regions are discussed in further detail below.

Crude oil prices in the Gulf Coast region are generally positive to NYMEX and highly correlated to the changes in prices of crude oil sold under Light Louisiana Sweet. Our average NYMEX oil differential in the Gulf Coast region was a positive $3.30 per Bbl during 2019, compared to a positive $2.94 per Bbl and a positive $0.22 per Bbl during 2018 and 2017, respectively. Our current markets at various sales points along the Gulf Coast have sufficient demand to accommodate our production, but there can be no assurance of future demand.

The marketing of our Rocky Mountain region oil production is dependent on transportation through local pipelines to market centers in Guernsey, Wyoming; Clearbrook, Minnesota; Wood River, Illinois; and most recently Cushing, Oklahoma. Shipments on some of the pipelines are at or near capacity and may be subject to apportionment. We currently have access to, or have contracted for, sufficient pipeline capacity to move our oil production; however, there can be no assurance that we will be allocated sufficient pipeline capacity to move all of our oil production in the future. Because local demand for production is small in comparison to current production levels, much of the production in the Rocky Mountain region is transported to markets outside of the region. Therefore, prices in the Rocky Mountain region are further influenced by fluctuations in prices (primarily Brent and LLS) in coastal markets and by available pipeline capacity in the Midwest and Cushing markets. For the year ended December 31, 2019, the discount for our oil production relative to NYMEX in the Rocky Mountain region averaged $2.01 per Bbl, compared to $1.50 per Bbl during 2018 and $1.39 per Bbl during 2017.

COMPETITION AND MARKETS

We face competition from other oil and natural gas companies in all aspects of our business, including acquisition of producing properties, oil and gas leases, drilling rights, and CO_2 properties; marketing of oil and natural gas; and obtaining and maintaining goods, services and labor. Many of our competitors have substantially larger financial and other resources. Factors that affect our ability to acquire producing properties include available liquidity, available information about prospective properties and our expectations for earning a minimum projected return on our investments. Because of the primary nature of our core assets (our tertiary operations) and our ownership of relatively uncommon significant natural sources of CO_2 in the Gulf Coast and Rocky Mountain regions, we believe that we are effective in competing in the market and have less competition than our peers in certain aspects of our business.

The demand for qualified and experienced field personnel to drill wells and conduct field operations and for geologists, geophysicists, engineers and other professionals in the oil and gas industry can fluctuate significantly, often in correlation with commodity prices, causing periodic shortages in such personnel. Prior to the downturn in oil prices, the competition for qualified technical personnel had been extensive, and our personnel costs escalated. There were also periods with shortages of drilling rigs and other equipment, as demand for rigs and equipment increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. We cannot be certain when we will experience these issues, and these types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results, and cause significant delays in our development operations.

FEDERAL AND STATE REGULATIONS

Numerous federal, state and local laws and regulations govern the oil and gas industry. Additions or changes to these laws and regulations are often made in response to the current political or economic environment. Compliance with the evolving regulatory landscape is often difficult, and substantial penalties may be incurred for noncompliance. Additionally, the future annual cost of complying with all laws and regulations applicable to our operations is uncertain and will be ultimately determined by several factors, including future changes to legal and regulatory requirements. Management believes that continued compliance with existing laws and regulations applicable to our operations and future compliance therewith will not have a materially adverse effect on our consolidated financial position, results of operations or cash flows, although such laws and regulations, and compliance therewith, could cause significant delays or otherwise impede operations, which may, among other things, cause our expected production rates and cash flows to be less than anticipated.

The following sections describe some specific laws and regulations that may affect us. We cannot predict the cost or impact of these or other future legislative or regulatory initiatives.

Regulation of Oil and Gas Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for drilling wells; maintaining bonding requirements in order to drill or operate wells and regulating the location of wells; the method of drilling and casing wells; the surface use and restoration of properties upon which wells are drilled; the plugging and abandoning of wells; and the composition or disposal of chemicals and fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling, spacing or proration units and the density of wells that may be drilled in those units, and the unitization or pooling of oil and gas properties. In addition, federal and state conservation laws, which establish maximum rates of production from oil and gas wells, generally prohibit or restrict the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these laws and regulations may limit the amount of oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. Regulatory requirements and compliance relative to the oil and gas industry increase our costs of doing business and, consequently, affect our profitability.

Federal Regulation of Sales Prices and Transportation

The transportation of, and certain sales with respect to, natural gas in interstate commerce are heavily regulated by agencies of the U.S. federal government and are affected by, among other things, the availability, terms and cost of transportation. Notably, the price and terms of access to pipeline transportation are subject to extensive U.S. federal and state regulation. The Federal Energy Regulatory Commission ("FERC") is continually proposing and implementing new and/or modified rules and regulations affecting the natural gas industry, some of which may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. While our sales of crude oil, condensate and natural gas liquids are not currently subject to FERC regulation, our ability to transport and sell such products is dependent on certain pipelines whose rates, terms and conditions of service are subject to FERC regulation. Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, FERC, state regulatory bodies and the courts, and we cannot predict when or if any such proposals or proceedings might become effective and their effect or impact, if any, on our operations.

Federal Energy and Climate Change Legislation and Regulation

The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, among other things, updated federal pipeline safety standards, increased penalties for violations of such standards, gave the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (the "PHMSA") authority for new damage prevention and incident notification, and directed the PHMSA to prescribe new minimum safety standards for CO_2 pipelines, which safety standards could affect our operations and the costs thereof. While the PHMSA has adopted or proposed to adopt a number of new regulations to implement this act, no new minimum safety standards have been proposed or adopted for CO_2 pipelines.

Both federal and state authorities have in recent years proposed new regulations to limit the emission of pollutants, including greenhouse gas emissions, as part of climate change initiatives and the Clean Air Act. For example, both the EPA and BLM have issued regulations for the control of methane emissions from the oil and gas industry. The EPA has promulgated regulations requiring permitting for certain sources of greenhouse gas emissions, and in May 2016, promulgated final regulations to reduce methane and volatile organic compound emissions from the oil and gas sector. In July 2017, a federal appeals court rejected an attempt by the EPA to delay implementation of the rule. In September 2018, the EPA proposed amendments to the rule that are targeted at reducing regulatory requirements and streamlining the rule's implementation. In September 2019, the EPA also issued a notice of proposed rulemaking that, if finalized, would remove the methane specific regulations imposed by the 2016 final rule and remove certain other emission limitations placed on new or reconstructed transmission and storage facilities. Enforcement of these regulations may impose additional costs related to compliance with new emission limits, as well as inspections and maintenance of several types of equipment used in our operations.

Natural Gas Gathering Regulations

State and federal regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. With the increase in construction and operation of natural gas gathering lines in various states, natural gas gathering is receiving greater regulatory scrutiny from state and federal regulatory agencies, which is likely to continue in the future.

Federal, State or Indian Leases

Our operations on federal, state or Indian oil and gas leases, especially those in the Rocky Mountain region, are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the Bureau of Land Management, the Bureau of Ocean Energy Management, the Bureau of Safety and Environmental Enforcement, the Bureau of Indian Affairs, and other federal and state stakeholder agencies.

Environmental Regulations

Our oil and natural gas production, saltwater disposal operations, injection of CO_2, and the processing, handling and disposal of materials such as hydrocarbons and naturally occurring radioactive materials ("NORM") are subject to stringent regulation. We could incur significant costs, including cleanup costs resulting from a release of product, third-party claims for property damage and personal injuries, or penalties and other sanctions as a result of any violations or liabilities under environmental laws and regulations or other laws and regulations applicable to our operations. Changes in, or more stringent enforcement of, environmental laws and other laws applicable to our operations could also result in delays or additional operating costs and capital expenditures.

Various federal, state and local laws and regulations controlling the discharge of materials into the environment, or otherwise relating to the protection of the environment and human health, directly impact our oil and gas exploration, development and production operations. These include, among others, (1) regulations adopted by the EPA and various state agencies regarding approved methods of disposal for certain hazardous and nonhazardous wastes; (2) the Comprehensive Environmental Response, Compensation, and Liability Act and analogous state laws that regulate the removal or remediation of previously disposed wastes (including wastes disposed of or released by prior owners or operators), property contamination (including groundwater contamination), and remedial plugging operations to prevent future contamination; (3) the Clean Air Act and comparable state and local requirements already applicable to our operations and new restrictions on air emissions from our operations, including greenhouse gas emissions and those that could discourage the production of fossil fuels that, when used, ultimately release CO_2; (4) the Clean Water Act and comparable state and local requirements already applicable to our operations and new restrictions on wastewater discharges from our operations; (5) the Oil Pollution Act of 1990, which contains numerous requirements relating to the prevention of, and response to, oil spills into waters of the United States; (6) the Resource Conservation and Recovery Act, which is the principal federal statute governing the treatment, storage and disposal of hazardous wastes; (7) the Endangered Species Act and counterpart state legislation, which protects certain species (and their related habitats), including certain species that could be present on our leases, as threatened or endangered; and (8) state regulations and statutes governing the handling, treatment, storage and disposal of NORM and other wastes.

In the Rocky Mountain Region, federal agencies' actions based upon their environmental review responsibilities under the National Environmental Policy Act can significantly impact the scope and timing of hydrocarbon development by slowing the timing of individual applications for permits to drill and requests for rights-of-way, and delaying large scale planning associated with region-level resource management plans and project-level master development plans.

Management believes that we are currently in substantial compliance with existing applicable environmental laws and regulations, and does not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position, results of operations or cash flows, although such laws and regulations, and compliance therewith, could cause significant delays or otherwise impede operations, which may, among other things, cause our expected production rates and cash flows to be less than anticipated.

Hydraulic Fracturing

During 2019, we fracture stimulated seven wells, primarily at Bell Creek Field utilizing water-based fluids. We currently have plans to potentially hydraulically fracture up to ten wells during 2020, consisting primarily of small skin fractures that are utilized to remove contaminants caused by drilling muds and increase permeability near the wellbore. We are familiar with the laws and regulations applicable to hydraulic fracturing operations and take steps to ensure compliance with these requirements.

NON-GAAP FINANCIAL MEASURES AND RECONCILIATIONS

Reconciliation of Standardized Measure to PV-10 Value

PV-10 Value is a non-GAAP measure and is different from the Standardized Measure in that PV-10 Value is a pre-tax number and the Standardized Measure is an after-tax number. The information used to calculate PV-10 Value is derived directly from data determined in accordance with FASC Topic 932. We believe that PV-10 Value is a useful supplemental disclosure to the Standardized Measure because the Standardized Measure can be impacted by a company's unique tax situation, and it is not practical to calculate the Standardized Measure on a property-by-property basis. Because of this, PV-10 Value is a widely used measure within the industry and is commonly used by securities analysts, banks and credit rating agencies to evaluate the estimated future net cash flows from proved reserves on a comparative basis across companies or specific properties. PV-10 Value is commonly used by us and others in our industry to evaluate properties that are bought and sold, to assess the potential return on investment in our oil and natural gas properties, and to perform our impairment testing of oil and natural gas properties. PV-10 Value is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for the Standardized Measure. Our PV-10 Value and the Standardized Measure do not purport to represent the fair value of our oil and natural gas reserves. See also *Glossary and Selected Abbreviations* for the definition of "PV-10 Value" and *Supplemental Oil and Natural Gas Disclosures (Unaudited)* to the Consolidated Financial Statements for additional disclosures about the Standardized Measure.

The following table provides a reconciliation of the Standardized Measure to PV-10 Value for the periods indicated:

	Year Ended December 31,		
In thousands	2019	2018	2017
Standardized Measure (GAAP measure)	$ 2,261,039	$ 3,351,385	$ 2,232,429
Discounted estimated future income tax	354,629	673,754	301,369
PV-10 Value (non-GAAP measure)	$ 2,615,668	$ 4,025,139	$ 2,533,798

Reconciliation of Net Income to Adjusted EBITDAX

Adjusted EBITDAX is a non-GAAP financial measure which management uses and is calculated based upon (but not identical to) a financial covenant related to "Consolidated EBITDAX" in our senior secured bank credit facility, which excludes certain items that are included in net income, the most directly comparable GAAP financial measure. Items excluded include interest, income taxes, depletion, depreciation, and amortization, and items that the Company believes affect the comparability of operating results such as items whose timing and/or amount cannot be reasonably estimated or are non-recurring. Management believes Adjusted EBITDAX may be helpful to investors in order to assess our operating performance as compared to that of other companies in our industry, without regard to financing methods, capital structure or historical costs basis. It is also commonly used by third parties to assess the Company's leverage and ability to incur and service debt and fund capital expenditures. Adjusted EBITDAX should not be considered in isolation, as a substitute for, or more meaningful than, net income, cash flows from operations, or any other measure reported in accordance with GAAP. The Company's Adjusted EBITDAX may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDAX, EBITDAX, or EBITDA in the same manner.

The following table presents a reconciliation of our net income to Adjusted EBITDAX for the periods indicated:

	Year Ended December 31,	
In thousands	2019	2018
Net income (GAAP measure)	$ 216,959	$ 322,698
Adjustments to reconcile to Adjusted EBITDAX		
Interest expense	81,632	69,688
Income tax expense	104,352	87,233
Depletion, depreciation, and amortization	233,816	216,449
Noncash fair value losses (gains) on commodity derivatives	93,684	(196,335)
Stock-based compensation	12,470	11,951
Gain on debt extinguishment	(155,998)	—
Severance-related expense	18,627	—
Accrued expense related to litigation over a helium supply contract	—	49,373
Impairment of loan receivable and related assets	—	17,805
Noncash, non-recurring and other	1,589	5,504
Adjusted EBITDAX (non-GAAP measure)	$ 607,131	$ 584,366

Item 1A. Risk Factors

Oil and natural gas prices are volatile. A sustained period of low of oil prices is likely to adversely affect our future financial condition, results of operations, cash flows and the carrying value of our oil and natural gas properties.

Oil prices are the most important determinant of our operational and financial success. Oil prices are highly impacted by worldwide oil supply, demand and prices, and have historically been subject to significant price changes over short periods of time. Over the last few years, NYMEX oil prices have been volatile, decreasing to a low of $43 in mid-2017 and gradually improving to hit a three-year peak of $76 in October 2018, before retreating to the low $40s in late December 2018 and generally averaging in the low $50s to mid $60s range throughout 2019. Based on past commodity cycles, volatility will remain, and prices could move downward or upward on a rapid or repeated basis, which can make planning and budgeting, acquisition and divestiture transactions, capital raising, valuations and sustaining business strategies more difficult. Our cash flow from operations is highly dependent on the prices that we receive for oil, as oil comprised approximately 97% of our 2019 production and approximately 98% of our proved reserves at December 31, 2019. The prices for oil and natural gas are subject to a variety of factors that are beyond our control. These factors include:

- the level of worldwide consumer demand for oil and natural gas, which has recently been negatively affected by concerns about the impact of the COVID-19 coronavirus, and the domestic and foreign supply of oil and natural gas and levels of domestic oil and natural gas storage;
- the degree to which members of the Organization of Petroleum Exporting Countries maintain oil price and production controls;
- the degree to which domestic oil and natural gas production affects worldwide supply of crude oil or its price;
- worldwide political events, conditions and policies, including actions taken by foreign oil and natural gas producing nations; and
- worldwide economic conditions.

Negative movements in oil prices could harm us in a number of ways, including:

- lower cash flows from operations may require reduced levels of capital expenditures;
- reduced levels of capital expenditures in turn could lower our present and future production levels, and lower the quantities and value of our oil and gas reserves, which constitute our major asset;
- our lenders could reduce our borrowing base, and we may not be able to raise capital at attractive rates in the public markets;
- we could have difficulty repaying or refinancing our indebtedness;
- we could be forced to increase our level of indebtedness, issue additional equity, or sell assets;
- we could be required to impair various assets, including a write-down of our oil and natural gas assets or the value of other tangible or intangible assets; and/or
- our potential cash flows from our commodity derivative contracts that include sold puts could be limited to the extent that oil prices are below the prices of those sold puts.

Furthermore, some or all of our tertiary projects could become or remain uneconomical. We may also decide to suspend future expansion projects, and if prices were to drop below our operating cash break-even points for an extended period of time, we may decide to shut-in existing production, both of which could have a material adverse effect on our operations and financial condition and reduce our production.

We must refinance, extend or repurchase $1.18 billion principal amount of our indebtedness which matures between May 2021 and May 2022 in order to maintain our continuing financial viability.

As of December 31, 2019, of our total outstanding debt principal of $2.3 billion, almost 50% becomes due and payable within 17 to 29 months, with $614.9 million due in May 2021. Our anticipated level of free cash flow during 2020, taken together with current borrowing capacity under our revolving credit facility, is not sufficient to repay all of our debt that is scheduled to mature in 2021 and 2022.

We are evaluating potential transactions to reduce, and/or extend maturities of, our long-term debt, focusing particularly on our second lien debt maturing in May 2021 and in March 2022. In conjunction with our debt reduction and extension efforts, we may engage in transactions of various types, including public or private capital raising, debt exchange transactions, debt repurchases with proceeds from joint ventures or asset sales, or some combination of these methods. However, our ability to restructure or refinance our long-term debt will depend on the condition of the capital markets and our financial condition at such time and could be affected by concentration in holdings of our long-term debt. Any refinancing of our long-term debt could be at higher interest rates and may require us to comply with more onerous debt covenants, which could further restrict our business operations or financial flexibility.

Without long-term access to capital, continued funding from lenders or sufficient generation of cash flow from our business operations, there continues to be substantial risk that we may be unable to repay or refinance our long-term indebtedness that matures in 2021 and 2022. Any failure to make timely payments of interest and principal when due on any of our outstanding long-term indebtedness could result in cross-defaults of all of our outstanding long-term indebtedness, which could then lead to acceleration of the maturities of such indebtedness and enforcement actions by the holders thereof to collect such indebtedness.

We may be unable to access the equity or debt capital markets to raise sufficient capital to meet our obligations in light of recent trends affecting the financing of the exploration and production sector.

Recent reluctance of traditional capital sources to invest in the exploration and production sector based on market volatility, perceived underperformance and environmental, social and governance (ESG) trends, has raised concerns regarding capital availability for the sector. The cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards and reduced (and in some cases ceased to provide) funding to borrowers. If those markets are unavailable, or if we are unable to access them or alternative financing sources on acceptable terms, we may be unable to repay our long-term debt or carry out our business strategy, with an accompanying negative impact on our financial condition, results of operations and ability to service our indebtedness.

Constraints on liquidity could limit our operational flexibility and growth.

In recent years, we have been successful in managing our capital expenditures so that they do not exceed our cash flows. Although our liquidity has been, and in 2020 is expected to remain, sufficient to support our capital expenditures and service our indebtedness, liquidity restrictions coming from lower oil prices and restraints on traditional capital sources for the exploration and production industry could negatively affect our level of capital expenditures, and thus our maintenance of production and operational cash flow. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity pressure, and might be required to dispose of material assets at unfavorable prices.

If we cannot meet the "price criteria" for continued listing on the NYSE, the NYSE may delist our common stock, which could have an adverse impact on the trading volume, liquidity and market price of our common stock, or the trading prices of our 6⅜% Convertible Senior Notes due 2024.

If we do not maintain an average closing price of $1.00 or more for our common stock over any consecutive 30 trading-day period, the NYSE may delist our common stock for a failure to maintain compliance with the NYSE price criteria listing standards. As of February 25, 2020, the average closing price of our common stock over the immediately preceding 30 consecutive trading day period was $1.04 per share, and our closing price was $0.84 per share on February 25, 2020. Despite NYSE rules and processes that provide a period of time to cure non-compliance with this NYSE standard (during which time the issuer's common stock generally continues to be traded on the NYSE), there is no assurance that trading prices of our common stock or other steps we take (such as a reverse stock split) would be successful in assuring our long-term listing on the NYSE. A delisting of our common stock from the NYSE would likely reduce the liquidity and market price of our common stock and the trading prices of our 6⅜% Convertible Senior Notes due 2024, reduce the number of investors willing to hold or acquire our common stock, and negatively impact our ability to raise equity financing.

A financial downturn in one or more of the world's major markets could negatively affect our business and financial condition.

In addition to the impact on the demand for oil, drops in domestic or foreign economic growth rates, regional or worldwide increases in tariffs or other trade restrictions, significant international currency fluctuations, evolving political and military tensions in the Middle East, a sustained credit crisis, or a worsening of the actual or anticipated future drop in worldwide oil demand due to the COVID-19 coronavirus, a severe economic contraction either regionally or worldwide or turmoil in the global financial system, could materially affect our business and financial condition or impact our ability to finance operations. Negative credit market conditions could inhibit our lenders from funding our senior secured bank credit facility or cause them to restrict our borrowing base or make the terms of our senior secured bank credit facility more costly and more restrictive. Negative economic conditions could also adversely affect the collectability of our trade receivables or performance by our suppliers or cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by increases in interest rates. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow, affect our interest costs under our senior secured bank credit facility, or increase the cost of any new debt financings.

Our bank credit facility maturity date "springs forward" to dates earlier than December 9, 2021 if certain conditions are not satisfied.

The Company's senior secured bank credit facility provides for acceleration of its December 9, 2021 maturity date to earlier dates during 2021, keyed to the maturity dates during 2021 of our 9% Senior Secured Second Lien Notes due May 15, 2021 (the "2021 Senior Secured Notes") and our 6⅜% Senior Subordinated Notes due August 15, 2021 (the "2021 Senior Subordinated Notes"), as follows:

- To February 12, 2021, if on that date the sum of the Company's cash, cash equivalents and borrowing availability under the senior secured bank credit facility is less than 120% of the amount of the then outstanding 2021 Senior Secured Notes;
- To May 14, 2021, if either (a) prior to that date the 2021 Senior Secured Notes have not been repaid or otherwise redeemed in full, or (b) on that date the sum of the Company's cash, cash equivalents and borrowing availability under the senior secured bank credit facility is less than 120% of the amount of the then outstanding 2021 Senior Subordinated Notes; or
- To August 13, 2021, if prior to that date the 2021 Senior Subordinated Notes have not been repaid or otherwise redeemed in full.

As of December 31, 2019, we had no outstanding borrowings and $87.2 million of letters of credit outstanding under our senior secured bank credit facility. The average outstanding balance under the credit facility as of the last day of each month during 2019 was $40.6 million. Our inability to repay amounts owing under our senior secured bank credit facility on any of the above springing maturity dates could trigger a cross-default under, and potentially an acceleration of, all of our other long-term indebtedness then outstanding. Based upon our use of the senior secured bank credit facility for short-term working capital purposes, we anticipate that any amounts outstanding from time to time under the credit facility during 2020 and 2021 can be repaid using our then-available cash flow from operations.

Inability to meet financial performance covenants in our bank credit facility may require us to seek modification of covenants, force a reduction in our borrowing base, or cause repayment of amounts outstanding under our bank credit facility.

In August 2018, we extended the maturity of our bank credit facility to December 2021 and reset certain financial performance covenants based on projections and oil price expectations that existed at that time. Oil prices subsequent to August 2018 have been volatile, and if oil and natural gas prices decrease for an extended period of time, we may not be able to remain in compliance with our senior secured bank credit facility's covenants. As such, we may be required to seek modifications of these covenants or a waiver at a significant cost to the Company, or the banks could force a reduction in our bank borrowing base and repayment of amounts outstanding under our bank credit facility. As of December 31, 2019, we had no bank debt outstanding, but we did have $87.2 million of letters of credit outstanding. If necessary, we may not be able to successfully modify these covenants or obtain a waiver of compliance with these covenants. For more information on our senior secured bank credit facility, see Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Senior Secured Bank Credit Facility*.

Our bank borrowing base is determined semiannually, and upon requested unscheduled special redeterminations, in each case at the banks' discretion, and the amount is established and based, in part, upon certain external factors, such as commodity prices. We do not know, nor can we control, the results of such redeterminations or the effect of then-current oil and natural gas prices on any such redetermination. A future redetermination lowering our borrowing base could limit availability under our senior secured bank credit facility or require us to seek different forms of financing arrangements. If the outstanding debt under our senior secured bank credit facility were to ever exceed the borrowing base, we would be required to repay the excess amount over a period not to exceed six months.

Certain of our operations may be limited during certain periods due to severe weather conditions and other regulations.

Our operations in the Gulf Coast region may be subjected to adverse weather conditions such as hurricanes, flooding and tropical storms in and around the Gulf of Mexico that can damage oil and natural gas facilities and delivery systems and disrupt operations, which can also increase costs and have a negative effect on our results of operations. Certain of our operations in North Dakota, Montana and Wyoming, including the construction of CO_2 pipelines, the drilling of new wells and production from existing wells, are conducted in areas subject to extreme weather conditions including severe cold, snow and rain, which conditions may cause such operations to be hindered or delayed, or otherwise require that they be conducted only during non-winter months, and depending on the severity of the weather, could have a negative effect on our results of operations in these areas. Further, the potential impacts of climate change on our operations may include unusually intense rainfall and storm patterns, rising sea levels and increased high temperatures.

Certain of our operations in the Rocky Mountain region are confined to certain time periods due to environmental regulations, federal restrictions on when drilling can take place on federal lands, and lease stipulations designed to protect certain wildlife, which regulations, restrictions and limitations could slow down our operations, cause delays, increase costs and have a negative effect on our results of operations. In addition, a number of governmental bodies have introduced or are contemplating regulatory changes in response to various climate change interest groups and the potential impact of climate change. Legislation and increased regulation regarding climate change could impose significant costs on us.

Given the political uncertainty about proposals to combat climate change and how it should be dealt with, it is possible that legislation and regulations could affect our financial condition and operating performance. However, even without such regulation, increased awareness and any adverse publicity in the global marketplace about potential impacts on climate change by our industry could harm our reputation and impact operations.

Oil and natural gas development and producing operations involve various risks.

Our operations are subject to all of the risks normally incident and inherent to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including, without limitation, pipe failure; fires; formations with abnormal pressures; uncontrollable flows of oil, natural gas, brine or well fluids; release of contaminants into the environment and other environmental hazards and risks and well blowouts, cratering or explosions. In addition, our operations are sometimes near populated commercial or residential areas, which adds additional risks. The nature of these risks is such that some liabilities could exceed our insurance policy limits or otherwise be excluded from, or limited by, our insurance coverage, as in the case of environmental fines and penalties, for example, which are excluded from coverage as they cannot be insured.

We could incur significant costs related to these risks that could have a material adverse effect on our results of operations, financial condition and cash flows or could have an adverse effect upon the profitability of our operations. Additionally, a portion of our production activities involves CO_2 injections into fields with wells plugged and abandoned by prior operators. However, it is often difficult (or impracticable) to determine whether a well has been properly plugged prior to commencing injections and pressuring the oil reservoirs. We may incur significant costs in connection with remedial plugging operations to prevent environmental contamination and to otherwise comply with federal, state and local regulations relative to the plugging and abandoning of our oil, natural gas and CO_2 wells. In addition to the increased costs, if wells have not been properly plugged, modification to those wells may delay our operations and reduce our production.

Development activities are subject to many risks, including the risk that we will not recover all or any portion of our investment in such wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, including hurricanes and tropical storms in and around the Gulf of Mexico that can damage oil and natural gas facilities and delivery systems and disrupt operations, and winter conditions and forest fires in the Rocky Mountain region that can delay or impede operations;

- compliance with environmental and other governmental requirements;
- the cost of, or shortages or delays in the availability of, drilling rigs, equipment, pipelines and services; and
- title problems.

Estimating our reserves, production and future net cash flows is difficult to do with any certainty.

Estimating quantities of proved oil and natural gas reserves is a complex process. It requires interpretations of available technical data and various assumptions, including future production rates, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, and the assumed effect of governmental rules and regulations. There are numerous uncertainties about when a property may have proved reserves as compared to potential or probable reserves, particularly relating to our tertiary recovery operations. Forecasting the amount of oil reserves recoverable from tertiary operations, and the production rates anticipated therefrom, requires estimates, one of the most significant being the oil recovery factor. Actual results most likely will vary from our estimates. Also, the use of a 10% discount factor for reporting purposes, as prescribed by the SEC, may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business, and the oil and natural gas industry in general, are subject. Any significant inaccuracies in these interpretations or assumptions, or changes of conditions, could result in a revision of the quantities and net present value of our reserves.

The reserves data included in documents incorporated by reference represents estimates only. Quantities of proved reserves are estimated based on economic conditions, including first-day-of-the-month average oil and natural gas prices for the 12-month period preceding the date of the assessment. The representative oil and natural gas prices used in estimating our December 31, 2019 reserves were $55.69 per Bbl for crude oil and $2.58 per MMBtu for natural gas, both of which were adjusted for market differentials by field. Our reserves and future cash flows may be subject to revisions based upon changes in economic conditions, including oil and natural gas prices, as well as due to production results, results of future development, operating and development costs, and other factors. Downward revisions of our reserves could have an adverse effect on our financial condition and operating results. Actual future prices and costs may be materially higher or lower than the prices and costs used in our estimates.

As of December 31, 2019, approximately 10% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and may require successful drilling operations. The reserves data assumes that we can and will make these expenditures and conduct these operations successfully, but these assumptions may not be accurate, and these expenditures and operations may not occur.

If commodity prices decline appreciably, we may be required to write down the carrying value of our oil and natural gas properties.

Under full cost accounting rules related to our oil and natural gas properties, we are required each quarter to perform a ceiling test calculation, with the net capitalized costs of our oil and natural gas properties limited to the lower of unamortized cost or the cost center ceiling. The present value of estimated future net revenues from proved oil and natural gas reserves included in the cost center ceiling is based on the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period prior to the end of a particular reporting period. Future material write-downs of our oil and natural gas properties, as well as future impairment of other long-lived assets, could significantly reduce earnings during the period in which such write-down and/or impairment occurs and would result in a corresponding reduction to long-lived assets and equity. See Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates*.

Our planned tertiary operations and the related construction of necessary CO_2 pipelines could be delayed by difficulties in obtaining pipeline rights-of-way and/or permits, and/or by the listing of certain species as threatened or endangered.

The production of crude oil from our planned tertiary operations is dependent upon having access to pipelines to transport available CO_2 to our oil fields at a cost that is economically viable. Our future construction of CO_2 pipelines will require us to obtain rights-of-way from private landowners, state and local governments and the federal government in certain areas. Certain states where we operate have considered or may again consider the adoption of laws or regulations that could limit or eliminate the ability of a pipeline owner or of a state, state's legislature or its administrative agencies to exercise eminent domain over private property, in addition to possible judicially imposed constraints on, and additional requirements for, the exercise of eminent domain. We also conduct operations on federal and other oil and natural gas leases inhabited by species that could be listed as threatened or endangered under the Endangered Species Act, which listing could lead to tighter restrictions as to federal land use and other land use where federal approvals are required. These laws and regulations, together with any other changes in law related to the use of eminent domain or the listing of certain species as threatened or endangered, could inhibit or eliminate our ability to secure rights-of-way or otherwise access land for current or future pipeline construction projects and may require additional regulatory and environmental compliance, and increased costs in connection therewith, which could delay our CO_2 pipeline construction schedule and initiation of our pipeline operations, and/or increase the costs of constructing our pipelines.

The ultimate cost of our planned 105-mile CCA pipeline extension may exceed our estimates, and there may be limited availability of capital for its construction. We may not be successful in entering into a joint venture for the extension and may be unable to raise third-party funds for our CCA pipeline extension spend in 2020. In addition, while we anticipate completion of the CCA pipeline extension by the end of 2020, the actual date of completion may be later due to, among other factors, capital constraints and the regulatory issues discussed above.

Our future performance depends upon our ability to effectively develop our existing oil and natural gas reserves and find or acquire additional oil and natural gas reserves that are economically recoverable.

Unless we can successfully develop our existing reserves and/or replace the reserves that we produce, our reserves will decline, resulting eventually in a decrease in oil and natural gas production and lower revenues and cash flows from operations. We have historically replaced reserves through both acquisitions and internal organic growth activities. For internal organic growth activities, the magnitude of proved reserves that we can book in any given year depends on our progress with new floods and the timing of the production response, as well as the success of exploitation projects. In the future, we may not be able to continue to replace reserves at acceptable costs. The business of exploring for, developing or acquiring reserves is capital intensive. We may not be able to make the necessary capital investment to maintain or expand our oil and natural gas reserves if our cash flows from operations are reduced, whether due to current oil or natural gas prices or otherwise, or if external sources of capital become limited or unavailable. Further, the process of using CO_2 for tertiary recovery, and the related infrastructure, requires significant capital investment prior to any resulting and associated production and cash flows from these projects, heightening potential capital constraints. If our capital expenditures are restricted, or if outside capital resources become limited, we will not be able to maintain our current production levels.

Commodity derivative contracts may expose us to potential financial loss.

To reduce our exposure to fluctuations in the prices of oil and natural gas, we enter into commodity derivative contracts in order to economically hedge a portion of our forecasted oil and natural gas production. As of February 24, 2020, we have oil derivative contracts in place covering 39,500 Bbls/d for the first half of 2020 and 35,500 Bbls/d for the second half of 2020. Such derivative contracts expose us to risk of financial loss in some circumstances, including when there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received, when the cash benefit from hedges including a sold put is limited to the extent oil prices fall below the price of our sold puts, or when the counterparty to the derivative contract is financially constrained and defaults on its contractual obligations. In addition, these derivative contracts may limit the benefit we would otherwise receive from increases in the prices for oil and natural gas.

Shortages of or delays in the availability of oil field equipment, services and qualified personnel could reduce our cash flow and adversely affect results of operations.

The demand for qualified and experienced field personnel, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, causing periodic shortages in such personnel. In the past, there have been shortages of oil field and other necessary equipment, including drilling rigs, along with increased prices for such equipment, services and associated personnel. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results and/or restrict or delay our ability to drill wells and conduct our operations, possibly causing us to miss our forecasts and projections.

The marketability of our production is dependent upon transportation lines and other facilities, certain of which we do not control. When these facilities are unavailable, our operations can be interrupted and our revenues reduced.

The marketability of our oil and natural gas production depends, in part, upon the availability, proximity and capacity of transportation lines owned by third parties. In general, we do not control these transportation facilities, and our access to them may be limited or denied. A significant disruption in the availability of, and access to, these transportation lines or other production facilities could adversely impact our ability to deliver to market or produce our oil and thereby cause a significant interruption in our operations.

Our production will decline if our access to sufficient amounts of carbon dioxide is limited.

Our long-term strategy is primarily focused on our CO_2 tertiary recovery operations. The crude oil production from our tertiary recovery projects depends, in large part, on having access to sufficient amounts of naturally occurring and industrial-sourced CO_2. Our ability to produce oil from these projects would be hindered if our supply of CO_2 was limited due to, among other things, problems with our current CO_2 producing wells and facilities, including compression equipment, catastrophic pipeline failure or our ability to economically purchase CO_2 from industrial sources. This could have a material adverse effect on our financial condition, results of operations and cash flows. Our anticipated future crude oil production from tertiary operations is also dependent on the timing, volumes and location of CO_2 injections and, in particular, on our ability to increase our combined purchased and produced volumes of CO_2 and inject adequate amounts of CO_2 into the proper formation and area within each of our tertiary oil fields.

The development of our naturally occurring CO_2 sources involves the drilling of wells to increase and extend the CO_2 reserves available for use in our tertiary fields. These drilling activities are subject to many of the same drilling and geological risks of drilling and producing oil and gas wells (see *Oil and natural gas development and producing operations involve various risks* above). Furthermore, recent market conditions may cause the delay or cancellation of construction of plants that produce industrial-source CO_2 as a byproduct that we can purchase, thus limiting the amount of industrial-source CO_2 available for our use in our tertiary operations.

A cyber incident could occur and result in information theft, data corruption, operational disruption, and/or financial loss.

Our business has become increasingly dependent on digital technologies to conduct day-to-day operations, including certain of our exploration, development and production activities. We depend on digital technology, among other things, to process and record financial and operating data; analyze seismic and drilling information; monitor and control pipeline and plant equipment; and process and store personally identifiable information of our employees and royalty owners. Cyber attacks on businesses have escalated in recent years. Our technologies, systems and networks may become the target of cyber attacks or information security breaches that could compromise our process control networks or other critical systems and infrastructure, resulting in disruptions to our business operations, harm to the environment or our assets, disruptions in access to our financial reporting systems, or loss, misuse or corruption of our critical data and proprietary information, including our business information and that of our employees, partners and other third parties. Any of the foregoing may be exacerbated by a delay or failure to detect a cyber incident. Cyber attacks could result in significant financial losses, legal or regulatory violations, reputational harm, and legal liability and could ultimately have a material adverse effect on our business and results of operations.

Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing and causing us to suffer such losses in the future. As cyber threats continue to evolve in magnitude and sophistication, we may be required to expend significant additional resources to continue to modify or enhance our procedures and controls or to investigate and remediate any digital and operational systems, related infrastructure, technologies and network security vulnerabilities, which could increase our costs.

We may lose key executive officers or specialized technical employees, which could endanger the future success of our operations.

Our success depends to a significant degree upon the continued contributions of our executive officers, other key management and specialized technical personnel. Our employees, including our executive officers, are employed at will and do not have employment agreements. We believe that our future success depends, in large part, upon our ability to hire and retain highly skilled personnel.

Environmental laws and regulations are costly and stringent.

Our exploration, production, and marketing operations are subject to complex and stringent federal, state, and local laws and regulations governing, among other things, the discharge of substances into the environment or otherwise relating to the protection of human health and the protection of endangered species. These laws and regulations and related public policy considerations affect the costs, manner, and feasibility of our operations and require us to make significant expenditures in order to comply. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial obligations, and the issuance of injunctions that could limit or prohibit our operations. Some of these laws and regulations may impose joint and several, strict liability for contamination resulting from spills, discharges, and releases of substances, including petroleum hydrocarbons and other wastes, without regard to fault, or the legality of the original conduct. Under such laws and regulations, we could be required to remove or remediate previously disposed substances and property contamination, including wastes disposed or released by prior owners or operators.

Enactment of executive, legislative or regulatory proposals under consideration could negatively affect our business.

Although the current Administration has moved away from the trend of proposing stricter standards and increasing oversight and regulation over the exploration and production industry at the federal level, it is possible that other proposals affecting the oil and gas industry could be enacted or adopted in the future, including state or local regulations, any of which could result in increased costs or additional operating restrictions that could have an effect on demand for oil and natural gas or prices at which it can be sold.

The loss of one or more of our large oil and natural gas purchasers could have an adverse effect on our operations.

For the year ended December 31, 2019, three purchasers individually accounted for 10% or more of our oil and natural gas revenues and, in the aggregate, for 54% of such revenues. The loss of a large single purchaser could adversely impact the prices we receive or the transportation costs we incur.

Item 1B. Unresolved Staff Comments

There are no unresolved written SEC staff comments regarding our periodic or current reports under the Securities Exchange Act of 1934 received 180 days or more before the end of the fiscal year to which this annual report on Form 10-K relates.

Item 2. Properties

Information regarding the Company's properties called for by this item is included in Item 1*, Business and Properties – Oil and Natural Gas Operations*. We also have various operating leases for rental of office space, office and field equipment, and vehicles. See Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Off-Balance Sheet Arrangements*, and Note 3, *Leases*, to the Consolidated Financial Statements for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our business or finances, litigation is subject to inherent uncertainties. We accrue for losses from litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

Riley Ridge Helium Supply Contract Claim

As part of our 2010 and 2011 acquisitions of the Riley Ridge Unit and associated gas processing facility that was under construction, the Company assumed a 20-year helium supply contract under which we agreed to supply the helium separated from the full well stream by operation of the gas processing facility to a third-party purchaser, APMTG Helium, LLC ("APMTG"). The helium supply contract provides for the delivery of a minimum contracted quantity of helium, with liquidated damages payable if specified quantities of helium are not supplied in accordance with the terms of the contract. The liquidated damages are capped at an aggregate of $46.0 million over the term of the contract.

As the gas processing facility has been shut-in since mid-2014 due to significant technical issues, we have not been able to supply helium under the helium supply contract. In a case filed in November 2014 in the Ninth Judicial District Court of Sublette County, Wyoming, APMTG claimed multiple years of liquidated damages for non-delivery of volumes of helium specified under the helium supply contract. The Company claimed that its contractual obligations were excused by virtue of events that fall within the force majeure provisions in the helium supply contract.

On March 11, 2019, the trial court entered a final judgment that a force majeure condition did exist, but the Company's performance was excused by the force majeure provisions of the contract for only a 35-day period in 2014, and as a result the Company should pay APMTG liquidated damages and interest thereon for those time periods from contract commencement to the close of evidence (November 29, 2017). The Company's position continues to be that its contractual obligations have been and continue to be excused by events that fall within the force majeure provisions of the helium supply contract, so the Company has appealed the trial court's ruling to the Wyoming Supreme Court. Briefing for the appeal by the Company and APMTG is currently expected to be completed in late May or early June, after which oral arguments will be scheduled and heard prior to the Wyoming Supreme Court entering its judgment on the appeal. The timing and outcome of this appeal process is currently unpredictable, but at this time is anticipated to extend over the next nine to twelve months.

Absent reversal of the trial court's ruling on appeal, the Company anticipates total liquidated damages would equal the $46.0 million aggregate cap under the helium supply contract plus $5.2 million of associated costs (through December 31, 2019), for a total of $51.2 million, which is included in "Other liabilities" in our Consolidated Balance Sheets as of December 31, 2019, and $49.4 million of which was accrued in the fourth quarter of 2018. The Company currently has a $32.8 million letter of credit posted as security in this case as part of the appeal process.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information and Holders of Record

Denbury's common stock is listed on the New York Stock Exchange under the symbol "DNR." As of January 31, 2020, based on information from the Company's transfer agent, Broadridge Stock Transfer Agent, the number of holders of record of Denbury's common stock was 1,169.

Dividends

We have not paid dividends on our common stock since the fourth quarter of 2015 and have no current plans to resume common stock dividends. Our Bank Credit Agreement and senior secured second lien, convertible senior, and senior subordinated note indentures require us to meet certain financial covenants at the time dividend payments are made. For further discussion, see Note 6, *Long-Term Debt*, to the Consolidated Financial Statements.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Month	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in millions)(2)
October 2019	20,102	$ 1.13	—	$ 210.1
November 2019	1,884	1.12	—	210.1
December 2019	—	—	—	210.1
Total	21,986		—	

(1) Shares purchased during the fourth quarter of 2019 were made in connection with the surrender of shares by our employees to satisfy their tax withholding requirements related to the vesting of restricted shares.

(2) In October 2011, we commenced a common share repurchase program, which has been approved for up to an aggregate of $1.162 billion of Denbury common shares by the Company's Board of Directors. This program has effectively been suspended and we do not anticipate repurchasing shares of our common stock in the near future. The program has no pre-established ending date and may be suspended or discontinued at any time. We are not obligated to repurchase any dollar amount or specific number of shares of our common stock under the program.

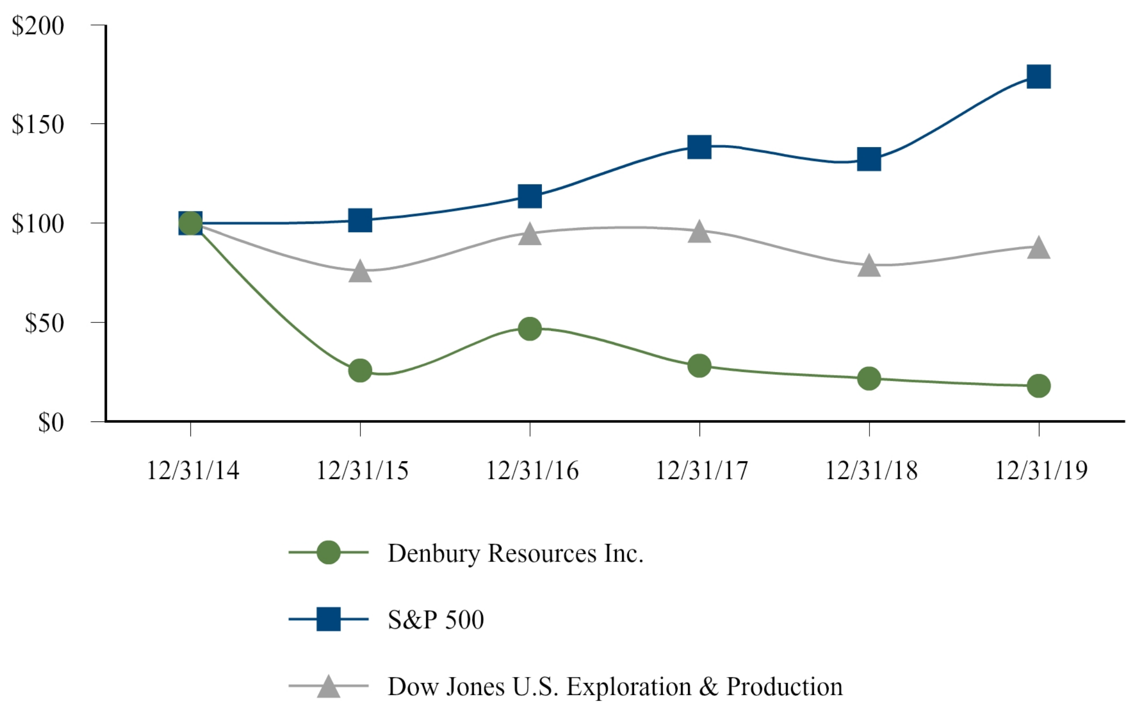
Denbury Resources Inc.

Stock Performance Graph

The following Performance Graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filings under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filings.

The following graph illustrates changes over the five-year period ended December 31, 2019, in cumulative total stockholder return on our common stock as measured against the cumulative total return of the S&P 500 Index and the Dow Jones U.S. Exploration and Production Index. The graph tracks the performance of a $100 investment in our common stock and in each index (with the reinvestment of all dividends for the index securities) from December 31, 2014, to December 31, 2019.

COMPARISON OF 5-YEAR CUMULATIVE TOTAL RETURN



	December 31,					
	2014	2015	2016	2017	2018	2019
Denbury Resources Inc.	$ 100	$ 26	$ 47	$ 28	$ 22	$ 18
S&P 500	100	101	114	138	132	174
Dow Jones U.S. Exploration & Production	100	76	95	96	79	88

Denbury Resources Inc.

Item 6. Selected Financial Data

In thousands, except per-share data or otherwise noted	Year Ended December 31, 2019	2018	2017	2016	2015
Consolidated Statements of Operations data					
Revenues and other income					
Oil, natural gas, and related product sales	$ 1,212,020	$ 1,422,589	$ 1,089,666	$ 935,751	$ 1,213,026
Other	62,863	51,036	40,120	39,845	44,534
Total revenues and other income	$ 1,274,883	$ 1,473,625	$ 1,129,786	$ 975,596	$ 1,257,560
Net income (loss)[1]	216,959	322,698	163,152	(976,177)	(4,385,448)
Net income (loss) per common share					
Basic[1]	0.47	0.75	0.42	(2.61)	(12.57)
Diluted[1]	0.45	0.71	0.41	(2.61)	(12.57)
Dividends declared per common share[2]	—	—	—	—	0.1875
Weighted average number of common shares outstanding					
Basic	459,524	432,483	390,928	373,859	348,802
Diluted	510,341	456,169	395,921	373,859	348,802
Consolidated Statements of Cash Flows data					
Cash provided by (used in)					
Operating activities	$ 494,143	$ 529,685	$ 267,143	$ 219,223	$ 864,304
Investing activities[3]	(269,692)	(333,276)	(356,814)	(204,663)	(549,730)
Financing activities	(246,355)	(157,452)	88,613	(15,012)	(334,460)
Production (average daily)					
Oil (Bbls)	56,672	58,532	58,410	61,440	69,165
Natural gas (Mcf)	9,246	10,854	11,329	15,378	22,172
BOE (6:1)	58,213	60,341	60,298	64,003	72,861
Unit sales prices – excluding impact of derivative settlements					
Oil (per Bbl)	$ 58.26	$ 66.11	$ 50.64	$ 41.12	$ 47.30
Natural gas (per Mcf)	2.06	2.58	2.41	1.98	2.35
Unit sales prices – including impact of derivative settlements					
Oil (per Bbl)	$ 59.40	$ 57.91	$ 48.40	$ 44.86	$ 67.41
Natural gas (per Mcf)	2.06	2.58	2.41	1.98	2.83
Costs per BOE					
Lease operating expenses[4]	$ 22.46	$ 22.24	$ 20.35	$ 17.71	$ 19.37
Taxes other than income	4.41	4.75	3.96	3.33	4.13
General and administrative expenses	3.91	3.25	4.63	4.69	5.44
Depletion, depreciation, and amortization[5]	11.00	9.83	9.44	36.12	19.99
Proved oil and natural gas reserves					
Oil (MBbls)	226,133	255,042	252,625	247,103	282,250
Natural gas (MMcf)	24,334	43,008	42,721	44,315	38,305
MBOE (6:1)	230,189	262,210	259,745	254,489	288,634
Proved carbon dioxide reserves					
Gulf Coast region (MMcf)[6]	4,786,881	4,982,440	5,164,741	5,332,576	5,501,175
Rocky Mountain region (MMcf)[7]	1,120,060	1,155,538	1,187,787	1,214,428	1,237,603
Consolidated Balance Sheets data					
Total assets	$ 4,691,867	$ 4,723,222	$ 4,471,299	$ 4,274,578	$ 5,885,533
Total long-term liabilities	2,915,366	3,216,652	3,365,077	3,372,634	4,263,606
Stockholders’ equity	1,412,259	1,141,777	648,165	468,448	1,248,912

(1) Includes pre-tax impairments of assets of $810.9 million and $6.2 billion for the years ended December 31, 2016 and 2015, respectively, and an accelerated depreciation charge of $591.0 million related to the Riley Ridge gas processing facility and related assets for the year ended December 31, 2016.

(2) In September 2015, in light of the low oil price environment and our desire to maintain our financial strength and flexibility, the Company's Board of Directors suspended our quarterly cash dividend.

(3) Reflects the adoption of Financial Accounting Standards Board ("FASB") Accounting Standards Update ("ASU") 2016-18, *Statement of Cash Flows* ("ASU 2016-18"), whereby changes in restricted cash are now included in the consolidated statements of cash flows. We adopted ASU 2016-18 effective January 1, 2018, which was applied retrospectively to all periods presented.

(4) Lease operating expenses reported in this table for 2015 include certain special items comprised of (1) lease operating expenses and related insurance recoveries recorded to remediate an area of Delhi Field, (2) a reimbursement for a retroactive utility rate adjustment, and (3) other insurance recoveries. If these special items are excluded, lease operating expenses would have totaled $528.8 million, or $19.88 per BOE, for the year ended December 31, 2015.

(5) Depletion, depreciation, and amortization during the year ended December 31, 2016 includes an accelerated depreciation charge of $591.0 million, or $25.23 per BOE, associated with the Riley Ridge gas processing facility and related assets.

(6) Proved CO_2 reserves in the Gulf Coast region consist of reserves from our reservoirs at Jackson Dome and are presented on a gross or 8/8ths working interest basis, of which our net revenue interest was approximately 3.8 Tcf, 4.0 Tcf, 4.1 Tcf, 4.2 Tcf and 4.4 Tcf at December 31, 2019, 2018, 2017, 2016 and 2015, respectively, and include reserves dedicated to volumetric production payments of 3.1 Bcf, 7.6 Bcf, 12.3 Bcf and 25.3 Bcf at December 31, 2018, 2017, 2016 and 2015, respectively (see *Supplemental CO_2 Disclosures (Unaudited)* to the Consolidated Financial Statements).

(7) Proved CO_2 reserves in the Rocky Mountain region consist of our overriding royalty interest in LaBarge Field, of which our net revenue interest was approximately 1.1 Tcf, 1.2 Tcf, 1.2 Tcf, 1.2 Tcf and 1.2 Tcf at December 31, 2019, 2018, 2017, 2016 and 2015, respectively (see *Supplemental CO_2 Disclosures (Unaudited)* to the Consolidated Financial Statements).

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our Consolidated Financial Statements and Notes thereto included in Item 8, *Financial Statements and Supplementary Information*. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with *Risk Factors* under Item 1A of this Form 10-K, along with *Forward-Looking Information* at the end of this section for information on the risks and uncertainties that could cause our actual results to be materially different from our forward-looking statements. For a discussion of the financial results for the fiscal year ended December 31, 2017, see Part II, Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*, of our Annual Report on Form 10-K for the fiscal year ended December 31, 2018, as filed with the SEC on March 1, 2019.

OVERVIEW

Denbury is an independent oil and natural gas company with operations focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of our properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to CO_2 enhanced oil recovery operations.

Oil Price Impact on Our Business. Our financial results are significantly impacted by changes in oil prices, as 97% of our production is oil. Changes in oil prices impact all aspects of our business, most notably our cash flows from operations, revenues, and capital allocation and budgeting decisions. The table below outlines changes in our realized oil prices over the last three years, before and after commodity hedging impacts:

	Year Ended December 31,		
	2019	2018	2017
Average net realized prices			
Oil price per Bbl - excluding impact of derivative settlements	$ 58.26	$ 66.11	$ 50.64
Oil price per Bbl - including impact of derivative settlements	59.40	57.91	48.40

We remained disciplined with our capital spending throughout 2019 despite oil prices averaging higher than the $50 per Bbl NYMEX oil price used in preparing our 2019 capital budget. Our 2019 capital expenditure level of $236.9 million was below the low end of our budgeted range of $240 million to $260 million, and we generated approximately $165 million of cash flow in excess of capital expenditures and capitalized interest (excluding working capital changes and severance-related expense, but including interest payments treated as repayment of debt in our financial statements).

Comparative Financial Results and Highlights. During 2019, we recognized net income of $217.0 million, or $0.45 per diluted common share, compared to net income of $322.7 million, or $0.71 per diluted common share, during 2018. The primary drivers of our change in operating results and per diluted share amounts between 2018 and 2019 were the following:

- Oil and natural gas revenues decreased by $210.6 million (15%), with 11% of the decrease due to lower commodity prices and 4% of the decrease due to lower production, offset in part by an improvement in derivative commodity settlements of $198.8 million from the prior year;
- Commodity derivative expense increased by $91.2 million, resulting from a $198.8 million improvement in cash settlements ($175.2 million of cash payments in 2018 compared to $23.6 million of cash receipts in 2019) which was more than offset by $290.0 million of expense for noncash fair value changes in commodity derivatives between 2018 and 2019;
- A noncash gain on debt extinguishment of $156.0 million in 2019 (see *2019 Debt Reduction Transactions* below);
- $18.6 million of severance expense in 2019 associated with our voluntary separation program (see *December 2019 Voluntary Separation Program* below);
- A $73.1 million reduction in other expense, as 2018 included $49.4 million of litigation expense and a $17.8 million asset impairment; and
- Our diluted per share net income in 2019 was affected by the inclusion of an additional 90.9 million shares of the Company's common stock issuable upon conversion of our convertible senior notes which were issued in June 2019, increasing our diluted share count by those shares for the portion of the year the notes were outstanding (see Note 1, *Nature of Operations and Summary of Significant Accounting Policies – Net Income per Common Share*, to the Consolidated Financial Statements).

2019 Debt Reduction Transactions. During 2019, we completed a series of debt exchanges and repurchases to extend the maturities of our outstanding long-term debt and reduce our debt principal as described below:

- During June 2019, through a series of debt exchanges, we extended the maturities of $348.4 million of our outstanding long-term debt to 2024 and reduced our debt principal by $120.0 million, with holders exchanging $468.4 million aggregate principal amount of our subordinated notes for:
  - $245.5 million aggregate principal amount of our new 6⅜% Convertible Senior Notes due 2024 (the "2024 Convertible Senior Notes");
  - $102.6 million aggregate principal amount of new 7¾% Senior Secured Second Lien Notes due 2024 (the "7¾% Senior Secured Notes"); and
  - $120.0 million of cash.

- During June and July 2019, as part of creating a more liquid series of secured second lien debt due in 2024, we also exchanged $429.2 million aggregate principal amount of 7¾% Senior Secured Notes for $429.4 million of previously outstanding 7½% Senior Secured Second Lien Notes due 2024. As a result of all of the above June and July note exchanges, we recognized a gain on debt extinguishment, net of transaction costs, totaling $100.5 million for the year ended December 31, 2019, in our Consolidated Statements of Operations.

- Between August and November 2019, we repurchased $112.1 million (approximately 31%) of our $357.8 million aggregate principal amount of senior subordinated notes outstanding as of June 30, 2019 for $16.4 million of cash and issuance of 38.3 million shares of the Company's common stock. In connection with these transactions, we recognized a $55.5 million gain on debt extinguishment, net of unamortized debt issuance costs written off, during the year ended December 31, 2019, in our Consolidated Statements of Operations.

The table below details the changes in our debt principal balances from December 31, 2018 to December 31, 2019:

In thousands	December 31, 2018	Change	December 31, 2019
Senior Secured Bank Credit Agreement	$ —	$ —	$ —
9% Senior Secured Second Lien Notes due 2021	614,919	—	614,919
9¼% Senior Secured Second Lien Notes due 2022	455,668	—	455,668
7¾% Senior Secured Second Lien Notes due 2024	—	531,821	531,821
7½% Senior Secured Second Lien Notes due 2024	450,000	(429,359)	20,641
6⅜% Convertible Senior Notes due 2024	—	245,548	245,548
6⅜% Senior Subordinated Notes due 2021	203,545	(152,241)	51,304
5½% Senior Subordinated Notes due 2022	314,662	(256,236)	58,426
4⅝% Senior Subordinated Notes due 2023	307,978	(172,018)	135,960
Pipeline financings	180,073	(12,634)	167,439
Capital lease obligations	5,362	(5,362)	—
Total debt principal balance	$ 2,532,207	$ (250,481)	$ 2,281,726

July 2019 Citronelle Field Divestiture. On July 1, 2019, we closed the sale of one of our mature Gulf Coast fields, Citronelle Field, for $10 million.

December 2019 Voluntary Separation Program. During December 2019, we made a voluntary separation program ("VSP") offer to certain eligible employees as part of the Company's ongoing efforts to reduce costs. One hundred employees (approximately 12% of our workforce) voluntarily chose to participate in the VSP, comprising employees both in corporate headquarters and in the field, with most of the impacted employees terminating employment by the end of January 2020. We recognized expense of $18.6 million in "General and administrative expenses" in our 2019 Consolidated Statements of Operations for severance and related costs. We estimate ongoing annual savings associated with the reduction in force to be approximately $21 million (starting in 2020), with such savings allocated across general and administrative expense (approximately 45%), lease operating expense (approximately 25%) and capitalized costs (approximately 30%).

Pending Sale of Working Interests in Certain Texas Fields. On December 20, 2019, we entered into a definitive agreement to sell half of our nearly 100% working interest positions in four conventional southeast Texas oil fields (consisting of Webster, Thompson, Manvel, and East Hastings) for $50 million cash and a carried interest in ten wells to be drilled by the purchaser (the "Pending Gulf Coast Working Interests Sale"). The sale is currently expected to occur in early March 2020. Under the agreement, the purchaser is committed to funding 100% of the capital required to drill and complete an initial ten horizontal wells across the fields, with the first of the ten wells to be spud within six months of closing and with all ten wells to be completed within 18 months after closing. On these initial ten wells, Denbury will receive a 6.25% overriding royalty interest prior to the combined payout of the wells in a specified field and subsequent to payout, Denbury will receive production revenues from, and bear the cost of, its 50% working interest in each well. As part of the agreement, we will retain 100% ownership of the future Webster Unit CO_2 flood, wherein (1) the purchaser may elect to participate in the future CO_2 flood through reimbursement to Denbury of the purchaser's working interest share of project costs incurred to date, or (2) if the purchaser declines to participate in the CO_2 flood, we have the right to repurchase the purchaser's working interest in Webster Field under a contractually agreed valuation mechanism.

CAPITAL RESOURCES AND LIQUIDITY

Overview. Our primary sources of capital and liquidity are our cash flows from operations and availability of borrowing capacity under our senior secured bank credit facility, which has been supplemented periodically by asset sale proceeds associated with sales of surface land with no active oil and natural gas operations and minor producing asset sales as discussed above. During 2019, we generated cash flows from operations of $494.1 million, while incurring capital expenditures of $236.9 million and capitalized interest of $36.7 million, resulting in approximately $165 million of cash flow in excess of capital expenditures (excluding working capital changes and severance-related expense, but including $85.3 million of interest payments treated as repayment of debt in our financial statements). As of December 31, 2019, we had no outstanding borrowings on our $615 million senior secured bank credit facility, consistent with December 31, 2018, leaving us with $527.8 million of borrowing base availability after consideration of $87.2 million of letters of credit outstanding.

Over the last several years of generally lower oil prices and high volatility, we have remained focused on our disciplined approach of spending within cash flow and preserving liquidity under our bank line. During this time, we have also remained keenly focused on reducing leverage and improving the Company's financial position, resulting in a $250.5 million reduction in our debt principal during 2019, which is on top of a $243.2 million reduction in our debt principal in 2018. In total, we reduced our outstanding debt principal by nearly $1.3 billion between December 31, 2014 and December 31, 2019, primarily through debt exchanges, opportunistic open market debt repurchases, and the conversion in the second quarter of 2018 of all of our then outstanding convertible senior notes into common stock. Our leverage metrics have improved considerably over the last several years, due primarily to our cost reduction efforts and our overall reduction in debt.

In 2019, we completed a series of debt exchanges and repurchases to extend the maturities of a portion of our long-term debt and reduce our debt principal (see *Overview – 2019 Debt Reduction Transactions*). Additionally, these exchange transactions could further contribute to debt reduction of up to $245.5 million if all of the 2024 Convertible Senior Notes convert to Company common stock at some time in the future, including automatic conversion into shares of common stock if the volume weighted average trading price of the Company's common stock equals or exceeds $2.43 per share for 10 trading days in any period of 15 consecutive trading days.

Although we have no significant maturities of debt in 2020, we have $614.9 million of 9% Senior Secured Second Lien Notes maturing on May 15, 2021 (the "2021 Senior Secured Notes") and $455.7 million of 9¼% Senior Secured Second Lien Notes due 2022 maturing on March 31, 2022 (the "2022 Senior Secured Notes"). In relation to the 2021 Senior Secured Notes, our bank credit agreement contains a springing maturity if such notes are not refinanced or their maturity is not extended by mid-February 2021 (see *Risk Factors – Our bank credit facility maturity date "springs forward" to dates earlier than December 9, 2021 if certain conditions are not satisfied*). We are actively evaluating options to reduce or extend the maturities of our long-term debt, with focus on our second lien debt maturing between May 2021 and March 2022. In conjunction with our debt reduction and extension efforts, we may engage in transactions of various types, including public or private capital raising, debt exchange transactions, debt repurchases with proceeds from joint ventures or asset sales, or some combination of these methods.

2020 Capital Budget. Since the beginning of 2020, NYMEX oil prices have moved downward by over $10 per barrel (from the low $60s per barrel in early January to around $50 per barrel in mid-February 2020), due in part to concerns about the COVID-19 coronavirus and its real and potential impact on near-term worldwide oil demand. In consideration of the current oil price environment and the Company's desire to preserve ongoing liquidity, we have set our 2020 base capital budget at between $175 million and $185 million (excluding capitalized interest), which includes $10 million of capital dedicated to continuing near-term CO_2 development activities at Cedar Creek Anticline ("CCA") as further discussed below. This 2020 base capital budget is a $57 million (24%) reduction from our 2019 actual capital expenditure level. We currently anticipate that our 2020 base capital budget of $175 million to $185 million will be more than fully funded with cash flow from operations (assuming a $50 per barrel NYMEX oil price) and should result in the Company generating upwards of $100 million of cash in excess of our capital expenditures, without including the proceeds from the Pending Gulf Coast Working Interests Sale (from which we expect net proceeds of approximately $40 million) or the impact of any other potential transactions. We also have oil price hedges on approximately 70% of our estimated 2020 production in order to protect against downward oil price volatility and to provide a degree of certainty in our 2020 estimated cash flow.

An additional $140 million to $150 million of capital for the CCA CO_2 tertiary flood development, most of which is scheduled to be spent in the second half of the year, is subject to the Company's ongoing assessment and evaluation of all relevant factors, including oil price changes and expectations, and the Company's capital resources and liquidity, and is conditioned upon future Board approval. The aggregate $155 million of planned 2020 CCA tertiary-related development capital consists of $105 million for the 105-mile extension of the Greencore Pipeline to CCA, with the remainder dedicated to facilities, well work and field development. The Company currently anticipates finalizing its 2020 capital plans for CCA during the second quarter.

Based on our capital spending plans, we currently anticipate 2020 average daily production to be between 53,000 and 56,000 BOE/d, after adjusting for the Pending Gulf Coast Working Interests Sale (see *Overview – Pending Sale of Working Interests in Certain Texas Fields*). The production associated with the Pending Gulf Coast Working Interests Sale averaged 1,170 BOE/d during the fourth quarter of 2019. Our anticipated 2020 production level compares to 2019 average continuing production of 56,914 BOE/d, after reduction for 2019 property divestitures and production associated with the Pending Gulf Coast Working Interests Sale.

Senior Secured Bank Credit Facility. In December 2014, we entered into an Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (as amended, the "Bank Credit Agreement"), which has been amended periodically since that time. The Bank Credit Agreement is a senior secured revolving credit facility with a maturity date of December 9, 2021, provided that the maturity date may occur earlier (February 12, 2021, May 14, 2021 or August 13, 2021) if our 2021 Senior Secured Notes or 6⅜% Senior Subordinated Notes due in August 2021, respectively, are not repaid or refinanced by each of their respective maturity dates (see *Risk Factors – Our bank credit facility maturity date "springs forward" to dates earlier than December 9, 2021 if certain conditions are not satisfied)*. The Bank Credit Agreement contains certain financial performance covenants through the maturity of the facility, including the following:

- A Consolidated Total Debt to Consolidated EBITDAX financial maintenance covenant, with such ratio not to exceed 5.25 to 1.0 through December 31, 2020 and 4.50 to 1.0 thereafter;
- A consolidated senior secured debt to consolidated EBITDAX covenant, with such ratio not to exceed 2.5 to 1.0. Only debt under our Bank Credit Agreement is considered consolidated senior secured debt for purposes of this ratio;
- A minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 1.25 to 1.0; and
- A requirement to maintain a current ratio (i.e., Consolidated Current Assets to Consolidated Current Liabilities) of 1.0 to 1.0.

For purposes of computing the current ratio per the Bank Credit Agreement, Consolidated Current Assets exclude the current portion of derivative assets but include borrowing base availability under the senior secured bank credit facility, and Consolidated Current Liabilities exclude the current portion of derivative liabilities as well as the current portions of long-term indebtedness outstanding.

Under these financial performance covenant calculations, as of December 31, 2019, our ratio of consolidated total debt to consolidated EBITDAX was 3.74 to 1.0 (with a maximum permitted ratio of 5.25 to 1.0), our ratio of consolidated senior secured debt to consolidated EBITDAX was 0.00 to 1.0 (with a maximum permitted ratio of 2.5 to 1.0), our ratio of consolidated EBITDAX to consolidated interest charges was 3.17 to 1.0 (with a required ratio of not less than 1.25 to 1.0), and our current ratio was 2.75 to 1.0 (with a required ratio of not less than 1.0 to 1.0). Based upon our currently forecasted levels of production and costs, hedges in place as of February 24, 2020, and current oil commodity futures prices, we currently anticipate continuing to be in compliance with our financial performance covenants during the foreseeable future.

The above description of our Bank Credit Agreement is qualified by the express language and defined terms contained in the Bank Credit Agreement and the amendments thereto, which are filed as exhibits to our periodic reports filed with the SEC.

2020 Capital Budget Allocation and Estimated Cash Flows. We have established a base 2020 capital expenditure budget, excluding capitalized interest and acquisitions, of between $175 million and $185 million, roughly a 24% decrease from 2019 capital spending levels of $236.9 million, with an additional $140 million to $150 million of capital for the CCA CO_2 tertiary flood development conditioned upon future Board approval (see *2020 Capital Budget*). Capitalized interest is currently estimated at approximately $40 million to $45 million for 2020. The 2020 capital budget, excluding capitalized interest and acquisitions, provides for approximate spending as follows:

- $75 million allocated for tertiary oil field expenditures;
- $55 million allocated for other areas, primarily non-tertiary oil field expenditures including exploitation;
- $10 million to be spent on CO_2 sources and pipelines; and
- $40 million for other capital items such as capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

An additional $140 million to $150 million of CCA CO_2 tertiary flood development capital is subject to Board approval. The aggregate planned 2020 CCA tertiary-related development capital consists of approximately $105 million for the 105-mile extension of the Greencore Pipeline to CCA, with the remainder dedicated to facilities, well work and field development.

Based upon our currently forecasted levels of production and costs, commodity hedges in place, and assuming a $50 NYMEX oil price in 2020, we expect that our cash flow from operations should significantly exceed our base 2020 capital expenditure budget of $175 million to $185 million, by upwards of $100 million. Assuming the additional $140 million to $150 million of CCA capital spending is approved, we would expect that our capital expenditures would be relatively equal to our cash resources (inclusive of cash flow from operations and $40 million of anticipated cash proceeds from the Pending Gulf Coast Working Interests Sale) before considering any other potential land sales. If prices were to decrease or changes in operating results were to cause a reduction in anticipated 2020 cash flows significantly below our currently forecasted operating cash flows, we would likely reduce our capital expenditures. Any sizeable reduction in our capital spending due to lower cash flows would likely lower our anticipated production levels in future years.

Capital Expenditure Summary. The following table reflects incurred capital expenditures (including accrued capital) for the years ended December 31, 2019, 2018 and 2017:

	Year Ended December 31,		
In thousands	2019	2018	2017
Capital expenditures by project			
Tertiary oil fields	$ 93,331	$ 142,560	$ 129,458
Non-tertiary fields	71,014	104,811	53,647
Capitalized internal costs(1)	46,031	46,599	52,616
Oil and natural gas capital expenditures	210,376	293,970	235,721
CO_2 pipelines, sources and other	26,545	28,700	5,105
Capital expenditures, before acquisitions and capitalized interest	236,921	322,670	240,826
Acquisitions of oil and natural gas properties	284	541	88,777
Capital expenditures, before capitalized interest	237,205	323,211	329,603
Capitalized interest	36,671	37,079	30,762
Capital expenditures, total	$ 273,876	$ 360,290	$ 360,365

(1) Includes capitalized internal acquisition, exploration and development costs and pre-production tertiary startup costs.

Commitments and Obligations. A summary of our obligations at December 31, 2019, is presented in the following table:

	Payments Due by Period				
In thousands	2020	2021 and 2022	2023 and 2024	Thereafter	Total
Contractual obligations					
Estimated interest payments on senior secured bank credit facility, senior secured second lien notes, convertible senior notes, and subordinated debt	$ 171,321	$ 211,661	$ 82,823	$ —	$ 465,805
Senior secured debt (principal balance)	—	1,070,587	552,462	—	1,623,049
Convertible senior notes (principal balance)	—	—	245,548	—	245,548
Subordinated debt (principal balance)	—	109,730	135,960	—	245,690
Operating lease obligations	9,934	20,315	20,617	8,287	59,153
Pipeline obligations including interest component	27,822	55,380	53,806	88,951	225,959
Other obligations(1)	60,836	93,600	65,469	89,615	309,520
Commodity derivative liabilities(2)	8,346	—	—	—	8,346
Asset retirement obligations(3)	4,652	—	51,727	744,729	801,108
Total contractual obligations	$ 282,911	$ 1,561,273	$ 1,208,412	$ 931,582	$ 3,984,178

(1) Represents future cash commitments under contracts in place as of December 31, 2019, primarily for purchase contracts for CO_2 captured from industrial sources, transportation agreements and well-related costs, but excludes any potential payments related to the APMTG litigation being appealed. As is common in our industry, we commit to make certain expenditures on a regular basis as part of our ongoing development and exploration program. These commitments generally relate to projects that occur during the subsequent several months and are usually part of our normal operating expenses or part of our capital budget (see *2020 Capital Budget Allocation and Estimated Cash Flows* above). We also have recurring expenditures for such things as accounting, engineering and legal fees; software maintenance; subscriptions; and other overhead-type items. Normally these expenditures do not change materially on an aggregate basis from year to year and are part of our general and administrative expenses. We have not attempted to estimate the amounts of these types of recurring expenditures in this table, as most could be quickly canceled with regard to any specific vendor, even though the expense itself may be required for our ongoing normal operations. For further discussion of our long-term commitments to purchase CO_2 and any payments related to the APMTG litigation being appealed, see Note 12, *Commitments and Contingencies*, to the Consolidated Financial Statements.

(2) Commodity derivative liabilities represent the fair value of our commodity derivatives presented as liabilities in our Consolidated Balance Sheets as of December 31, 2019. The ultimate settlement amounts of our derivative obligations are unknown because they are subject to continuing market fluctuations. See further discussion of our commodity derivative contracts and their market price sensitivities in *Market Risk Management* below in this *Management's Discussion and Analysis of Financial Condition and Results of Operations*, and in Note 10, *Commodity Derivative Contracts*, to the Consolidated Financial Statements.

(3) Represents the estimated future asset retirement obligations on an undiscounted basis. The present value of the discounted asset retirement obligation is $181.8 million, as determined under the *Asset Retirement and Environmental Obligations* topic of the Financial Accounting Standards Board Codification ("FASC"), and is further discussed in Note 4, *Asset Retirement Obligations*, to the Consolidated Financial Statements.

Off-Balance Sheet Arrangements. As of December 31, 2019, we had a total of $87.2 million of letters of credit outstanding under our senior secured bank credit facility, which outstanding total increased during 2019 principally due to posting of a $32.8 million letter of credit as part of the appeal process in the APMTG litigation in Wyoming. Additionally, we have obligations for development and exploratory expenditures that arise from our normal capital expenditure program or from other transactions common to our industry, none of which are recorded on our balance sheet. These obligations are further described in *Commitments and Obligations* above. In addition, in order to recover our undeveloped proved reserves, we must also fund the associated future development costs estimated in our proved reserve reports, which are only included in the table above to the extent we have firm contracts. For a further discussion of our future development costs, see *Supplemental Oil and Natural Gas Disclosures (Unaudited)* to the Consolidated Financial Statements.

FINANCIAL OVERVIEW OF TERTIARY OPERATIONS

As discussed in Item 1, *Business and Properties – Oil and Natural Gas Operations – Enhanced Oil Recovery Overview* , our tertiary operations represent a significant portion of our overall operations and have become our primary strategic focus. The economics of a tertiary field and the related impact on our financial statements differ from a conventional oil and gas play and are explained further below.

While it is difficult to accurately forecast future production, we believe our tertiary recovery operations provide significant long-term production growth potential at reasonable return metrics, with relatively low risk, assuming crude oil prices are at levels that support the development of those projects. We have been developing tertiary oil properties for over 20 years, and the financial impact of such operations is reflected in our historical financial statements. The summary below highlights our observations regarding how tertiary operations have impacted our financial statements.

Finding and Development Costs. We currently expect finding and development costs (including future development and abandonment costs but excluding CO_2 pipeline infrastructure capital expenditures) over the life of each field to be competitive with the industry average costs for other oil properties. See the definition of finding and development costs in the *Glossary and Selected Abbreviations*.

Timing of Capital Costs. When initiating a new tertiary flood, there generally is a delay between the initial capital expenditures and the resulting production increases. We must build facilities, and often a CO_2 pipeline to the field, before CO_2 flooding can commence, and it usually takes six to twelve months before the field responds to the injection of CO_2 (i.e., oil production commences). Further, we may spend significant amounts of capital before we can recognize any proved reserves from fields we flood and, even after a field has proved reserves, significant amounts of additional capital will usually be required to fully develop the field.

Recognition of Proved Reserves. In order to recognize proved tertiary oil reserves, we must either demonstrate production resulting from the tertiary process or the field must be analogous to an existing tertiary flood. The magnitude of proved reserves that we can book in any given year will depend on our progress with new floods, the timing of the production response from new floods and the performance of our existing floods. Typically, a high percentage of the potential reserves for a tertiary field are recognized when a production response is initially observed, and generally only modest changes are made thereafter.

Production Rates. The production rate at a tertiary flood can vary from quarter to quarter, as a tertiary field's production may increase rapidly when wells respond to the CO_2, plateau temporarily, and then resume growth as additional areas of the field are developed. During a tertiary flood life cycle, facility capacity is increased from time to time, which occasionally requires temporary shutdowns during installation, thereby causing temporary declines in production. We also find it difficult to precisely predict when any given well will respond to the injected CO_2, as the CO_2 seldom travels through the rock consistently due to heterogeneity in the oil-bearing formations. With the lower level of oil prices over the past several years, our pace of development has generally slowed, thereby reducing our Company-wide production rates. We find all of these fluctuations to be normal and generally expect oil production at a tertiary field to increase over time until the field is fully developed, albeit sometimes in inconsistent patterns.

Operating Costs. Tertiary projects may be more expensive to operate than traditional industry operations because of the cost of injecting and recycling the CO_2 (primarily due to the cost of the CO_2 and the significant energy requirements to re-compress the CO_2 back into a near-liquid state for re-injection purposes). The costs of our CO_2 and the electricity required to recycle and inject this CO_2 comprise nearly half of our typical tertiary operating expenses. Since these costs vary along with commodity and commercial electricity prices, they are highly variable and will increase in a high-commodity-price environment and decrease in a low-price environment. The cost of purchasing and/or producing CO_2 for use in tertiary floods is allocated to our tertiary oil fields and recorded as lease operating expenses (following the commencement of tertiary oil production) at the time the CO_2 is injected. These costs have historically represented approximately 20% to 25% of the total operating costs for our tertiary operations. Since we expense all of the operating costs to produce and inject our CO_2 (following the commencement of tertiary oil production), operating costs per barrel for a new flood will be higher at the inception of CO_2 injection projects because of minimal related oil production at that time.

RESULTS OF OPERATIONS

Operating Results Table

Certain of our operating results and statistics for each of the last three years are included in the following table.

In thousands, except per share and unit data	Year Ended December 31, 2019	2018	2017
Operating results			
Net income	$ 216,959	$ 322,698	$ 163,152
Net income per common share – basic	0.47	0.75	0.42
Net income per common share – diluted	0.45	0.71	0.41
Net cash provided by operating activities	494,143	529,685	267,143
Average daily production volumes			
Bbls/d	56,672	58,532	58,410
Mcf/d	9,246	10,854	11,329
BOE/d	58,213	60,341	60,298
Operating revenues			
Oil sales	$ 1,205,083	$ 1,412,358	$ 1,079,703
Natural gas sales	6,937	10,231	9,963
Total oil and natural gas sales	$ 1,212,020	$ 1,422,589	$ 1,089,666
Commodity derivative contracts(1)			
Receipt (payment) on settlements of commodity derivatives	$ 23,606	$ (175,248)	$ (47,795)
Noncash fair value gains (losses) on commodity derivatives(2)	(93,684)	196,335	(29,781)
Commodity derivatives income (expense)	$ (70,078)	$ 21,087	$ (77,576)
Unit prices – excluding impact of derivative settlements			
Oil price per Bbl	$ 58.26	$ 66.11	$ 50.64
Natural gas price per Mcf	2.06	2.58	2.41
Unit prices – including impact of derivative settlements(1)			
Oil price per Bbl	$ 59.40	$ 57.91	$ 48.40
Natural gas price per Mcf	2.06	2.58	2.41
Oil and natural gas operating expenses			
Lease operating expenses	$ 477,220	$ 489,720	$ 447,799
Transportation and marketing expenses	41,810	43,942	44,064
Production and ad valorem taxes	86,820	96,589	79,198
Oil and natural gas operating revenues and expenses per BOE			
Oil and natural gas revenues	$ 57.04	$ 64.59	$ 49.51
Lease operating expenses	22.46	22.24	20.35
Transportation and marketing expenses	1.97	2.00	2.00
Production and ad valorem taxes	4.09	4.39	3.60
CO_2 sources – revenues and expenses			
CO_2 sales and transportation fees	$ 34,142	$ 31,145	$ 26,182
CO_2 discovery and operating expenses	(2,922)	(2,816)	(3,099)
CO_2 revenue and expenses, net	$ 31,220	$ 28,329	$ 23,083

(1) See also *Commodity Derivative Contracts* below and *Market Risk Management* for information concerning our commodity derivative transactions.

(2) Noncash fair value gains (losses) on commodity derivatives is a non-GAAP measure and is different from "Commodity derivatives expense (income)" in the Consolidated Statements of Operations in that the noncash fair value gains (losses) on commodity derivatives represent only the net changes between periods of the fair market values of commodity derivative

positions, and exclude the impact of settlements on commodity derivatives during the period, which were receipts on settlements of $23.6 million for the year ended December 31, 2019 and payments on settlements of $175.2 million and $47.8 million for the years ended December 31, 2018 and 2017, respectively. We believe that noncash fair value gains (losses) on commodity derivatives is a useful supplemental disclosure to "Commodity derivatives expense (income)" in order to differentiate noncash fair market value adjustments from receipts or payments upon settlements on commodity derivatives during the period. This supplemental disclosure is widely used within the industry and by securities analysts, banks and credit rating agencies in calculating EBITDA and in adjusting net income (loss) to present those measures on a comparative basis across companies, as well as to assess compliance with certain debt covenants. Noncash fair value gains (losses) on commodity derivatives is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for "Commodity derivatives expense (income)" in the Consolidated Statements of Operations. See also the *Glossary and Selected Abbreviations* for the definition of noncash fair value gains (losses) on commodity derivatives.

Production

Average daily production by area for 2019, 2018 and 2017, and for each of the quarters of 2019, is shown below:

	Average Daily Production (BOE/d)						
	2019 Quarters				Year Ended December 31,		
Operating Area	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	2019	2018	2017
Tertiary oil production							
Gulf Coast region							
Delhi	4,474	4,486	4,256	4,085	4,324	4,368	4,869
Hastings	5,539	5,466	5,513	5,097	5,403	5,596	4,830
Heidelberg	3,987	4,082	4,297	4,409	4,195	4,355	4,851
Oyster Bayou	4,740	4,394	3,995	4,261	4,345	4,843	5,007
Tinsley	4,659	4,891	4,541	4,343	4,608	5,530	6,430
West Yellow Creek	436	586	728	807	640	205	13
Mature properties(1)	6,479	6,448	6,415	6,347	6,422	6,702	7,078
Total Gulf Coast region	30,314	30,353	29,745	29,349	29,937	31,599	33,078
Rocky Mountain region							
Bell Creek	4,650	5,951	4,686	5,618	5,228	4,113	3,313
Salt Creek(2)	2,057	2,078	2,213	2,223	2,143	2,109	1,115
Grieve	52	41	58	60	53	7	—
Total Rocky Mountain region	6,759	8,070	6,957	7,901	7,424	6,229	4,428
Total tertiary oil production	37,073	38,423	36,702	37,250	37,361	37,828	37,506
Non-tertiary oil and gas production							
Gulf Coast region							
Mississippi	1,034	1,025	873	952	970	960	981
Texas(3)	4,345	4,243	4,268	4,382	4,310	4,546	4,493
Other	10	6	6	5	6	13	81
Total Gulf Coast region	5,389	5,274	5,147	5,339	5,286	5,519	5,555
Rocky Mountain region							
Cedar Creek Anticline	14,987	14,311	13,354	13,730	14,090	14,837	14,754
Other	1,313	1,305	1,238	1,192	1,262	1,431	1,537
Total Rocky Mountain region	16,300	15,616	14,592	14,922	15,352	16,268	16,291
Total non-tertiary production	21,689	20,890	19,739	20,261	20,638	21,787	21,846
Total continuing production	58,762	59,313	56,441	57,511	57,999	59,615	59,352
Property sales							
Property divestitures(4)	456	406	—	—	214	726	946
Total production	59,218	59,719	56,441	57,511	58,213	60,341	60,298

(1) Mature properties include Brookhaven, Cranfield, Eucutta, Little Creek, Mallalieu, Martinville, McComb and Soso fields.

(2) Represents production related to the acquisition of a 23% non-operated working interest in Salt Creek Field in Wyoming, which closed on June 30, 2017.

(3) Includes non-tertiary production related to the sale of 50% of our working interests in Webster, Thompson, Manvel, and East Hastings fields, which is expected to close in March 2020 and averaged 1,170 BOE/d and 1,085 BOE/d for the three and twelve months ended December 31, 2019, respectively.

(4) Includes production from Citronelle Field sold in July 2019 and Lockhart Crossing Field sold in the third quarter of 2018.

Total Production

Total continuing production during 2019 averaged 57,999 BOE/d, including 37,361 Bbls/d from tertiary properties and 20,638 BOE/d from non-tertiary properties. Total continuing production excludes production from Citronelle Field sold in July 2019 and, for prior-year periods, excludes production from Lockhart Crossing Field sold in the third quarter of 2018. Our 2019 total continuing production level represents a decrease of 1,616 BOE/d (3%) compared to 2018 levels, most significantly attributable to lower tertiary production at Tinsley Field primarily due to planned downtime and preventative maintenance and lower non-tertiary production at CCA, partially offset by production increases from Bell Creek Field's phase 5 development. Our production during 2019 was 97% oil, consistent with 2018 and 2017.

Oil and Natural Gas Revenues

Oil and natural gas revenues decreased 15% between 2018 and 2019 and increased 31% between 2017 and 2018. The changes in our oil and natural gas revenues are due to changes in production quantities and realized commodity prices (excluding any impact of our commodity derivative contracts), as reflected in the following table:

	Year Ended December 31, 2019 vs. 2018		Year Ended December 31, 2018 vs. 2017	
In thousands	Decrease in Revenues	Percentage Decrease in Revenues	Increase in Revenues	Percentage Increase in Revenues
Change in oil and natural gas revenues due to:				
Increase (decrease) in production	$ (50,163)	(4)%	$ 765	0%
Increase (decrease) in commodity prices	(160,406)	(11)%	332,158	31%
Total increase (decrease) in oil and natural gas revenues	$ (210,569)	(15)%	$ 332,923	31%

Excluding any impact of our commodity derivative contracts, our average net realized commodity prices and NYMEX differentials were as follows during 2019, 2018 and 2017:

	Year Ended December 31,		
	2019	2018	2017
Average net realized prices			
Oil price per Bbl	$ 58.26	$ 66.11	$ 50.64
Natural gas price per Mcf	2.06	2.58	2.41
Price per BOE	57.04	64.59	49.51
Average NYMEX differentials			
Gulf Coast region			
Oil per Bbl	$ 3.30	$ 2.94	$ 0.22
Natural gas per Mcf	(0.04)	0.09	(0.04)
Rocky Mountain region			
Oil per Bbl	$ (2.01)	$ (1.50)	$ (1.39)
Natural gas per Mcf	(0.96)	(1.06)	(1.15)
Total Company			
Oil per Bbl	$ 1.23	$ 1.30	$ (0.32)
Natural gas per Mcf	(0.47)	(0.49)	(0.61)

Prices received in a regional market fluctuate frequently and can differ from NYMEX pricing due to a variety of reasons, including supply and/or demand factors, crude oil quality, and location differentials.

- **Gulf Coast Region**. Our average NYMEX oil differential in the Gulf Coast region was a positive $3.30 per Bbl and a positive $2.94 per Bbl during 2019 and 2018, respectively. Generally, our Gulf Coast region differentials are positive to

NYMEX and highly correlated to the changes in prices of Light Louisiana Sweet crude oil, which have generally strengthened over the past year, although Gulf Coast region differentials softened in the second half of 2019.

- **Rocky Mountain Region.** NYMEX oil differentials in the Rocky Mountain region averaged $2.01 per Bbl below NYMEX during 2019, compared to an average differential of $1.50 per Bbl below NYMEX in 2018. Differentials in the Rocky Mountain region can fluctuate significantly on a month-to-month basis due to weather, refinery or transportation issues, and Canadian and U.S. crude oil price index volatility.

CO_2 Revenues and Expenses

We sell approximately 15% to 20% of our produced CO_2 from Jackson Dome to third-party industrial users at various contracted prices primarily under long-term contracts. We recognize the revenue received on these CO_2 sales as "CO_2 sales and transportation fees" with the corresponding costs recognized as "CO_2 discovery and operating expenses" in our Consolidated Statements of Operations.

Purchased Oil Revenues and Expenses

From time to time, we market third-party production for sale in exchange for a fee. We recognize the revenue received on these oil sales as "Purchased oil sales" and the expenses incurred to market and transport the oil as "Purchased oil expenses" in our Consolidated Statements of Operations.

Commodity Derivative Contracts

We routinely enter into oil derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil production and to provide more certainty to our future cash flows. These contracts have historically consisted of price floors, collars, three-way collars, fixed-price swaps, fixed-price swaps enhanced with a sold put, and basis swaps.

The following table summarizes the impact our commodity derivative contracts had on our operating results for 2019, 2018 and 2017:

	Three Months Ended				
In thousands	March 31	June 30	September 30	December 31	Full Year
2019					
Receipt (payment) on settlements of commodity derivatives	$ 8,206	$ (1,549)	$ 8,057	$ 8,892	$ 23,606
Noncash fair value gains (losses) on commodity derivatives(1)	(91,583)	26,309	35,098	(63,508)	(93,684)
Commodity derivatives income (expense)	$ (83,377)	$ 24,760	$ 43,155	$ (54,616)	$ (70,078)
2018					
Payment on settlements of commodity derivatives	$ (33,357)	$ (54,770)	$ (61,611)	$ (25,510)	$ (175,248)
Noncash fair value gains (losses) on commodity derivatives(1)	(15,468)	(41,429)	17,034	236,198	196,335
Commodity derivatives income (expense)	$ (48,825)	$ (96,199)	$ (44,577)	$ 210,688	$ 21,087
2017					
Receipt (payment) on settlements of commodity derivatives	$ (26,940)	$ (11,767)	$ 89	$ (9,177)	$ (47,795)
Noncash fair value gains (losses) on commodity derivatives(1)	51,542	22,140	(25,352)	(78,111)	(29,781)
Commodity derivatives income (expense)	$ 24,602	$ 10,373	$ (25,263)	$ (87,288)	$ (77,576)

(1) Noncash fair value gains (losses) on commodity derivatives is a non-GAAP measure. See *Operating Results Table* above for a discussion of the reconciliation between noncash fair value gains (losses) on commodity derivatives to "Commodity derivatives expense (income)" in the Consolidated Statements of Operations. See also the *Glossary and Selected Abbreviations* for the definition of noncash fair value gains (losses) on commodity derivatives.

In order to provide a level of price protection to a portion of our oil production, we have hedged a portion of our estimated oil production in 2020 using both NYMEX and LLS fixed-price swaps and three-way collars. See Note 10, *Commodity Derivative Contracts*, to the Consolidated Financial Statements for additional details of our outstanding commodity derivative contracts as of December 31, 2019, and *Market Risk Management* below for additional discussion. In addition, the following table summarizes our oil derivative contracts as of February 24, 2020:

		1H 2020	2H 2020
WTI NYMEX	Volumes Hedged (Bbls/d)	2,000	2,000
Fixed-Price Swaps	Swap Price(1)	$60.59	$60.59
Argus LLS	Volumes Hedged (Bbls/d)	4,500	4,500
Fixed-Price Swaps	Swap Price(1)	$62.29	$62.29
WTI NYMEX	Volumes Hedged (Bbls/d)	23,000	21,000
3-Way Collars	Sold Put Price / Floor / Ceiling Price(1)(2)	$48.25 / $56.95 / $62.83	$48.26 / $56.85 / $62.68
Argus LLS	Volumes Hedged (Bbls/d)	10,000	8,000
3-Way Collars	Sold Put Price / Floor / Ceiling Price(1)(2)	$52.85 / $61.52 / $68.21	$52.75 / $61.08 / $68.39
	Total Volumes Hedged (Bbls/d)	39,500	35,500

(1) Averages are volume weighted.
(2) If oil prices were to average less than the sold put price, receipts on settlement would be limited to the difference between the floor price and the sold put price.

Commodity derivative contracts in place for 2020 include fixed-price swaps and three-way collars. Based on current contracts in place and NYMEX oil futures prices as of February 24, 2020, which average approximately $52 per Bbl for the remainder of 2020, we currently expect that we would receive cash payments of approximately $80 million during 2020 upon settlement of these contracts, the amount of which is dependent upon fluctuations in future NYMEX oil prices in relation to the prices of our 2020 fixed-price swaps which have weighted average prices of $60.59 per Bbl and $62.29 per Bbl for NYMEX and LLS hedges, respectively, and weighted average floor prices of our 2020 three-way collars of $56.90 per Bbl and $61.32 per Bbl for NYMEX and LLS hedges, respectively. The cash flows from our three-way collars could be limited to the extent that oil prices fall below the prices of our sold puts, which generally range between $45 per Bbl and $50 per Bbl for NYMEX hedges and $51 per Bbl and $55 per Bbl for LLS hedges. See Note 10, *Commodity Derivative Contracts*, to the Consolidated Financial Statements for further discussion of the sold puts. Changes in commodity prices, expiration of contracts, and new commodity contracts entered into cause fluctuations in the estimated fair value of our oil derivative contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the period-to-period changes in the fair value of these contracts, as outlined above, are recognized in our statements of operations.

Production Expenses

Lease Operating Expenses

	Year Ended December 31,		
In thousands, except per-BOE data	2019	2018	2017
Total lease operating expenses	$ 477,220	$ 489,720	$ 447,799
Total lease operating expenses per BOE	$ 22.46	$ 22.24	$ 20.35

Total lease operating expense during 2019 decreased $12.5 million (3%) on an absolute-dollar basis, but slightly increased $0.22 (1%) on a per-BOE basis, compared to 2018. The decrease on an absolute-dollar basis was primarily due to lower workover expense, lower power and fuel costs, and lower CO_2 expense due to lower CO_2 volumes delivered during planned maintenance at our primary CO_2 source in the Rocky Mountain region during the third quarter of 2019, partially offset by higher contract labor costs.

Currently, our CO_2 expense comprises approximately 20% of our typical tertiary lease operating expenses, and for the CO_2 reserves we already own, consists of CO_2 production expenses, and for the CO_2 reserves we do not own, consists of our purchase of CO_2 from royalty and working interest owners and industrial sources. During the year ended December 31, 2019, approximately

56% of the CO_2 utilized in our CO_2 floods consisted of CO_2 owned and produced by us (our net revenue interest). The price we pay others for CO_2 varies by source and is generally indexed to oil prices. When combining the production cost of the CO_2 we own with what we pay third parties for CO_2, our average cost of CO_2 during 2019 was approximately $0.29 per Mcf, including taxes paid on CO_2 production but excluding depletion, depreciation and amortization of capital expended at our CO_2 source fields and industrial sources. This per-Mcf CO_2 cost during 2019 was lower than the $0.42 per Mcf comparable measure during 2018 due primarily to lower utilization of industrial-source CO_2, which has a higher average cost than our naturally occurring CO_2 sources.

Transportation and Marketing Expenses

Transportation and marketing expenses primarily consist of amounts incurred related to the transportation, marketing, and processing of oil and natural gas production. Transportation and marketing expenses were $41.8 million and $43.9 million during 2019 and 2018, respectively.

Taxes Other than Income

Taxes other than income includes production, ad valorem and franchise taxes. Taxes other than income decreased $10.9 million (10%) between 2018 and 2019, due primarily to a decrease in production taxes resulting from lower oil and natural gas revenues.

General and Administrative Expenses ("G&A")

	Year Ended December 31,		
In thousands, except per-BOE data and employees	2019	2018	2017
Gross cash compensation and administrative costs	$ 209,408	$ 220,127	$ 244,477
Gross stock-based compensation	16,488	15,438	19,721
Severance-related costs	18,627	—	6,226
Operator labor and overhead recovery charges	(121,677)	(126,570)	(127,425)
Capitalized exploration and development costs	(39,817)	(37,500)	(41,193)
Net G&A expense	$ 83,029	$ 71,495	$ 101,806
G&A per BOE			
Net cash administrative costs	$ 2.44	$ 2.70	$ 3.66
Net stock-based compensation	0.59	0.55	0.69
Severance-related costs	0.88	—	0.28
Net G&A expense	$ 3.91	$ 3.25	$ 4.63
Employees as of December 31	806	847	879

Our gross G&A expenses, which include our field operations employee costs, on an absolute-dollar basis increased $9.0 million (4%) between 2018 and 2019 due to $18.6 million of severance-related expense associated with our voluntary separation program, the majority of which will be paid out in the first quarter of 2020 (see *Overview – December 2019 Voluntary Separation Program*). Excluding the severance expense, net G&A expense was down $7.1 million primarily due to our continued focus on cost reduction efforts and reduction in performance-based compensation.

Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. In addition, salaries associated with field personnel are initially recorded as gross cash compensation and administrative costs and subsequently reclassified to lease operating expenses or capitalized to field development costs to the extent those individuals are dedicated to oil and natural gas production, exploration, and development activities.

Interest and Financing Expenses

	Year Ended December 31,		
In thousands, except per-BOE data and interest rates	2019	2018	2017
Cash interest(1)	$ 191,454	$ 186,632	$ 176,307
Less: interest not reflected as expense for financial reporting purposes(1)	(85,454)	(86,111)	(52,473)
Noncash interest expense	4,554	6,246	6,191
Amortization of debt discount(2)	7,749	—	—
Less: capitalized interest	(36,671)	(37,079)	(30,762)
Interest expense, net	$ 81,632	$ 69,688	$ 99,263
Interest expense, net per BOE	$ 3.84	$ 3.16	$ 4.51
Average debt principal outstanding(3)	$ 2,433,245	$ 2,593,035	$ 2,892,785
Average interest rate(4)	7.9%	7.2%	6.1%

(1) Cash interest includes the portion of interest on certain debt instruments accounted for as a reduction of debt for GAAP financial reporting purposes in accordance with Financial Accounting Standards Board Codification ("FASC") 470-60, *Troubled Debt Restructuring by Debtors*. The portion of interest treated as a reduction of debt relates to our 2021 Senior Secured Notes, 2022 Senior Secured Notes, and our previously outstanding 3½% Convertible Senior Notes due 2024 and 5% Convertible Senior Notes due 2023 (the "2023 Convertible Senior Notes"). See below for further discussion.
(2) Represents amortization of debt discounts of $2.6 million related to the 7¾% Senior Secured Notes and $5.1 million related to the 2024 Convertible Senior Notes during the year ended December 31, 2019.
(3) Excludes debt discounts related to our 7¾% Senior Secured Notes and 2024 Convertible Senior Notes.
(4) Includes commitment fees but excludes debt issue costs and amortization of discount.

As reflected in the table above, cash interest expense during 2019 increased when compared to 2018 due primarily to an increase in our weighted-average interest rate.

Future interest payable related to our 2021 Senior Secured Notes, 2022 Senior Secured Notes, and previously outstanding 2023 Convertible Senior Notes and 3½% Convertible Senior Notes due 2024 is accounted for in accordance with FASC 470-60, *Troubled Debt Restructuring by Debtors*, whereby most of the future interest was recorded as debt as of the transaction date, which will be reduced as semiannual interest payments are made. Future interest payable recorded as debt totaled $164.9 million and $250.2 million as of December 31, 2019 and 2018, respectively. Therefore, interest expense reflected in our Consolidated Statements of Operations will be approximately $86 million lower annually than the actual cash interest payments on our 2021 Senior Secured Notes and 2022 Senior Secured Notes.

As more fully described in Note 6, *Long-Term Debt*, to the Consolidated Financial Statements, the June 2019 debt exchange transactions were accounted for in accordance with FASC 470-50, *Modifications and Extinguishments*, whereby our new 7¾% Senior Secured Notes and new 2024 Convertible Senior Notes were recorded on our balance sheet at discounts to their principal amounts of $29.6 million and $79.9 million, respectively. These debt discounts will be amortized as interest expense over the terms of the notes; therefore, future interest expense reflected in our Consolidated Statements of Operations will be higher than the actual cash interest payments on our new 7¾% Senior Secured Notes and new 2024 Convertible Senior Notes by approximately $16 million in 2020, $19 million in 2021, $21 million in 2022, $25 million in 2023 and $21 million in 2024.

Depletion, Depreciation, and Amortization ("DD&A")

	Year Ended December 31,		
In thousands, except per-BOE data	2019	2018	2017
Oil and natural gas properties	$ 159,478	$ 134,486	$ 118,792
CO_2 properties, pipelines, plants and other property and equipment	74,338	81,963	88,921
Total DD&A	$ 233,816	$ 216,449	$ 207,713
DD&A per BOE			
Oil and natural gas properties	$ 7.51	$ 6.11	$ 5.40
CO_2 properties, pipelines, plants and other property and equipment	3.49	3.72	4.04
Total DD&A per BOE	$ 11.00	$ 9.83	$ 9.44

The increase in our oil and natural gas properties depletion during 2019, when compared to 2018, was primarily due to an increase in depletable costs resulting from increases in our capitalized costs and future development costs associated with our reserves base and a decrease in proved oil and natural gas reserve quantities. Our oil and natural gas properties depletion rate was $8.17 per BOE during the fourth quarter of 2019.

Other Expenses

Other expenses totaled $11.2 million and $84.3 million during 2019 and 2018, respectively. Other expenses during 2019 includes $1.9 million of impairment expense, $1.8 million of costs associated with the Riley Ridge helium supply contract ruling (see Note 12, *Commitments and Contingencies – Litigation*, to the Consolidated Financial Statements), and $1.6 million of transaction costs associated with our privately negotiated debt exchanges. The 2018 amounts are primarily comprised of $49.4 million of expense related to the Riley Ridge helium supply contract ruling and a $17.8 million impairment for an investment related to a proposed plant in the Gulf Coast that would potentially supply CO_2 to Denbury, due to uncertainties of the project achieving financial close.

Income Taxes

	Year Ended December 31,		
In thousands, except per-BOE amounts and tax rates	2019	2018	2017
Current income tax expense (benefit)	$ 3,881	$ (16,001)	$ (20,873)
Deferred income tax expense (benefit)	100,471	103,234	(95,779)
Total income tax expense (benefit)	$ 104,352	$ 87,233	$ (116,652)
Average income tax expense (benefit) per BOE	$ 4.91	$ 3.96	$ (5.30)
Effective tax rate	32.5%	21.3%	(250.9)%
Total net deferred tax liability	$ 410,230	$ 309,758	$ 198,099

Our income tax provisions were based on an estimated statutory rate of approximately 25% for 2019 and 2018 and 38% for 2017. The Tax Cut and Jobs Act (the "Act") enacted in December 2017 resulted in a reduction of the federal income tax rate from 35% to 21% effective for calendar year 2018. Our effective tax rate for 2019 was higher than our estimated statutory rate primarily due to the establishment of a valuation allowance against a portion of our business interest expense deduction that we estimate will be disallowed. Our 2018 and 2017 effective tax rates were lower than our estimated statutory rate primarily due to tax benefits resulting from enhanced oil recovery income tax credits and a one-time deferred income tax benefit of $132.2 million reflecting a re-measurement of our deferred income tax assets and liabilities associated with the federal income tax rate reduction, respectively. As of December 31, 2019, we had a tax valuation allowance totaling $77.2 million to reduce the carrying value of deferred tax assets related to our disallowed business interest expense and state deferred tax assets. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized.

The current income tax benefit recorded in 2018 primarily represents the estimated receivable associated with our refundable alternative minimum tax credits.

As of December 31, 2019, we had no federal net operating loss carryforwards ("NOLs"), tax effected business interest expense carryforward totaling $24.5 million (before provision for valuation allowance), state NOLs and tax credits totaling $52.9 million (before provision for valuation allowance), an estimated $49.9 million of enhanced oil recovery credits to carry forward related to our tertiary operations and $21.6 million of research and development credits that can be utilized to reduce our current income taxes during 2020 or future years. We also have $6.0 million of alternative minimum tax credits, which under the Act will be fully refundable by 2021 and are recorded as a receivable on the balance sheet. Our business interest expense carryforward does not expire. Our state NOLs expire in various years, starting in 2020, although most do not begin to expire until 2025. Our enhanced oil recovery credits and research and development credits do not begin to expire until 2025 and 2031, respectively. The statutes of limitation for our income tax returns for tax years ending prior to 2016 have lapsed and therefore are not subject to examination by respective taxing authorities.

Per-BOE Data

The following table summarizes our cash flow and results of operations on a per-BOE basis for the comparative periods. Each of the individual components is discussed above.

	Year Ended December 31,		
Per-BOE data	2019	2018	2017
Oil and natural gas revenues	$ 57.04	$ 64.59	$ 49.51
Receipt (payment) on settlements of commodity derivatives	1.11	(7.96)	(2.17)
Lease operating expenses	(22.46)	(22.24)	(20.35)
Production and ad valorem taxes	(4.09)	(4.39)	(3.60)
Transportation and marketing expenses	(1.97)	(2.00)	(2.00)
Production netback	29.63	28.00	21.39
CO_2 sales, net of operating and exploration expenses	1.47	1.28	1.05
General and administrative expenses(1)	(3.91)	(3.25)	(4.63)
Interest expense, net	(3.84)	(3.16)	(4.51)
Other	0.43	(2.01)	1.67
Changes in assets and liabilities relating to operations	(0.52)	3.19	(2.83)
Cash flows from operations	23.26	24.05	12.14
DD&A	(11.00)	(9.83)	(9.44)
Deferred income taxes	(4.73)	(4.69)	4.35
Gain on early extinguishment of debt	7.34	—	—
Noncash fair value gains (losses) on commodity derivatives(2)	(4.41)	8.92	(1.35)
Other noncash items	(0.25)	(3.80)	1.71
Net income	$ 10.21	$ 14.65	$ 7.41

(1) General and administrative expenses includes an accrual for severance-related costs of $18.6 million associated with our voluntary separation program for the year ended December 31, 2019 and payments of $6.2 million related to an involuntary workforce reduction for the year ended December 31, 2017, which if excluded, would have averaged $3.03 per BOE and $4.35 per BOE for the years ended December 31, 2019 and 2017, respectively.

(2) Noncash fair value gains (losses) on commodity derivatives is a non-GAAP measure. See *Operating Results Table* above for a discussion of the reconciliation between noncash fair value gains (losses) on commodity derivatives to "Commodity derivatives expense (income)" in the Consolidated Statements of Operations. See also the *Glossary and Selected Abbreviations* for the definition of noncash fair value gains (losses) on commodity derivatives.

MARKET RISK MANAGEMENT

Debt and Interest Rate Sensitivity

At December 31, 2019, we had $2.1 billion of fixed-rate long-term debt and no outstanding borrowings on our variable-rate senior secured bank credit facility. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies, although under the NEJD financing lease, in light of credit downgrades in February 2016, we were required to provide a $41.3 million letter of credit to the lessor, which we provided on March 4, 2016. The letter of credit may be drawn upon in the event we fail to make a payment due under the pipeline financing lease agreement or upon other specified defaults set out in the pipeline financing lease agreement (filed as Exhibit 99.1 to the Form 8-K filed with the SEC on June 5, 2008). The fair values of our senior secured second lien notes, convertible senior notes, and senior subordinated notes are based on quoted market prices. The following table presents the principal and fair values of our outstanding debt at December 31, 2019:

In thousands	2021	2022	2023	2024	Total	Fair Value
Fixed rate debt						
9% Senior Secured Second Lien Notes due 2021	$ 614,919	$ —	$ —	$ —	$ 614,919	$ 599,546
9¼% Senior Secured Second Lien Notes due 2022	—	455,668	—	—	455,668	428,328
7¾% Senior Secured Second Lien Notes due 2024	—	—	—	531,821	531,821	468,002
7½% Senior Secured Second Lien Notes due 2024	—	—	—	20,641	20,641	17,132
6⅜% Convertible Senior Notes due 2024	—	—	—	245,548	245,548	158,450
6⅜% Senior Subordinated Notes due 2021	51,304	—	—	—	51,304	41,171
5½% Senior Subordinated Notes due 2022	—	58,426	—	—	58,426	36,224
4⅝% Senior Subordinated Notes due 2023	—	—	135,960	—	135,960	84,295

Commodity Derivative Contracts

We enter into oil derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil production and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps, fixed-price swaps enhanced with a sold put, and basis swaps. The production that we hedge has varied from year to year depending on our levels of debt, financial strength, and expectation of future commodity prices. In order to provide a level of price protection to a portion of our oil production, we have hedged a portion of our estimated oil production in 2020 using both NYMEX and LLS fixed-price swaps and three-way collars. Depending on market conditions, we may continue to add to our existing 2020 hedges or enter into hedges for 2021. See also Note 10, *Commodity Derivative Contracts*, and Note 11*, Fair Value Measurements,* to the Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

All of the mark-to-market valuations used for our commodity derivatives are provided by external sources. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification. All of our commodity derivative contracts are with parties that are lenders under our senior secured bank credit facility (or affiliates of such lenders). We have included an estimate of nonperformance risk in the fair value measurement of our commodity derivative contracts, which we have measured for nonperformance risk based upon credit default swaps or credit spreads.

For accounting purposes, we do not apply hedge accounting to our commodity derivative contracts. This means that any changes in the fair value of these commodity derivative contracts will be charged to earnings instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings.

At December 31, 2019, our commodity derivative contracts were recorded at their fair value, which was a net asset of $3.6 million, a $93.7 million decrease from the $97.3 million net asset recorded at December 31, 2018. This change is primarily related to the expiration of commodity derivative contracts during 2019, new commodity derivative contracts entered into during 2019 for future periods, and changes in oil futures prices between December 31, 2018 and 2019.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices as of December 31, 2019, and assuming both a 10% increase and decrease thereon, we would expect to receive payments on our crude oil derivative contracts as shown in the following table:

In thousands	Receipt / (Payment)
Based on:	
Futures prices as of December 31, 2019	$ 6,962
10% increase in prices	(43,601)
10% decrease in prices	67,752

Our commodity derivative contracts are used as an economic hedge of our exposure to commodity price risk associated with anticipated future production. As a result, changes in receipts or payments of our commodity derivative contracts due to changes in commodity prices, as reflected in the above table, would be mostly offset by a corresponding increase or decrease in the cash receipts on sales of our oil and natural gas production to which those commodity derivative contracts relate.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with generally accepted accounting principles requires that we select certain accounting policies and make certain estimates and judgments regarding the application of those policies. Our significant accounting policies are included in Note 1, *Nature of Operations and Summary of Significant Accounting Policies*, to the Consolidated Financial Statements. These policies, along with the underlying assumptions and judgments by our management in their application, have a significant impact on our consolidated financial statements. Following is a discussion of our most critical accounting estimates, judgments and uncertainties that are inherent in the preparation of our financial statements.

Full Cost Method of Accounting, Depletion and Depreciation and Oil and Natural Gas Properties

Businesses involved in the production of oil and natural gas are required to follow accounting rules that are unique to the oil and gas industry. We apply the full cost method of accounting for our oil and natural gas properties. Another acceptable method of accounting for oil and natural gas production activities is the successful efforts method of accounting. In general, the primary differences between the two methods are related to the capitalization of costs and the evaluation for asset impairment. Under the full cost method, all geological and geophysical costs, exploratory dry holes and delay rentals are capitalized to the full cost pool, whereas under the successful efforts method such costs are expensed as incurred. In the assessment of impairment of oil and natural gas properties, the successful efforts method follows the *Accounting for the Impairment or Disposal of Long-Lived Assets* topic of the FASC, under which the net book value of assets is measured for impairment against the undiscounted future cash flows using commodity prices consistent with management expectations. Under the full cost method, the full cost pool (net book value of oil and natural gas properties) is measured against future cash flows discounted at 10% using the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period through the end of each quarterly reporting period. The financial results for a given period could be substantially different depending on the method of accounting that an oil and gas entity applies. Further, we do not designate our oil and natural gas derivative contracts as hedging instruments for accounting purposes under the *Derivatives and Hedging* topic of the FASC (see below), and as a result, these contracts are not considered in the full cost ceiling test.

We make significant estimates at the end of each period related to accruals for oil and natural gas revenues, production, capitalized costs and operating expenses. We calculate these estimates with our best available data, which includes, among other things, production reports, price posting, information compiled from daily drilling reports and other internal tracking devices, and analysis of historical results and trends. While management is not aware of any required revisions to its estimates, there will likely be future adjustments resulting from such things as revisions in estimated oil and natural gas volumes, changes in ownership interests, payouts, joint venture audits, re-allocations by the purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which will require retroactive application. These types of adjustments cannot be currently estimated or determined and will be recorded in the period during which the adjustment occurs.

Under full cost accounting, the estimated quantities of proved oil and natural gas reserves used to compute depletion and the related present value of estimated future net cash flows therefrom used to perform the full cost ceiling test have a significant impact on the underlying financial statements. The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continued reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure the reported reserve estimates represent the most accurate assessments possible, including the hiring of independent engineers to prepare reported estimates, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in our financial statement disclosures. Over the last four years, annual revisions to our reserve estimates, excluding any revisions related to changes in commodity prices, have averaged approximately 2.0% of the previous year's estimates and have been both positive and negative.

Changes in commodity prices also affect our reserve quantities. These changes in quantities affect our DD&A rate, and the combined effect of changes in quantities and commodity prices impacts our full cost ceiling test calculation. For example, we estimate that a 5% increase in our estimate of proved reserve quantities would have lowered our fourth quarter 2019 oil and natural gas property DD&A rate from $8.17 per BOE to approximately $7.82 per BOE, and a 5% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $8.56 per BOE. Also, reserve quantities and their ultimate values, determined solely by our lenders, are the primary factors in determining the maximum borrowing base under our senior secured bank credit facility, particularly quantities and values of our proved developed producing reserves.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as (1) the present value of estimated future net revenues from proved oil and natural gas reserves before future abandonment costs (discounted at 10%), based on the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period prior to the end of a particular reporting period; plus (2) the cost of properties not being amortized; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) related income tax effects. Our future net revenues from proved oil and natural gas reserves are not reduced for development costs related to the cost of drilling for and developing CO_2 reserves nor those related to the cost of constructing CO_2 pipelines, as we do not have to incur additional costs to develop the proved oil and natural gas reserves. Therefore, we include in the ceiling test, as a reduction of future net revenues, that portion of our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves. The fair value of our oil and natural gas derivative contracts is not included in the ceiling test, as we do not designate these contracts as hedging instruments for accounting purposes. The cost center ceiling test is prepared quarterly. We did not record any ceiling test write-downs during 2017, 2018 or 2019.

We exclude certain unevaluated costs from the amortization base and full cost ceiling test pending the determination of whether proved reserves can be assigned to such properties. These costs are transferred to the full cost amortization base in the course of these properties being developed, tested and evaluated. At least annually, we test these assets for impairment based on an evaluation of management's expectations of future pricing, evaluation of lease expiration terms, and planned project development activities. As a result of this analysis, we recognized impairments of our unevaluated costs totaling $18.2 million and $21.4 million during the years ended December 31, 2019 and 2017, respectively, whereby these costs were transferred to the full cost amortization base. We did not record any impairments of our unevaluated costs during the year ended December 31, 2018.

Tertiary Injection Costs

Our tertiary operations are conducted in reservoirs that have already produced significant amounts of oil over many years; however, in accordance with the rules for recording proved reserves, we cannot recognize proved reserves associated with enhanced recovery techniques such as CO_2 injection until we can demonstrate production resulting from the tertiary process or unless the field is analogous to an existing flood. Our costs associated with the CO_2 we produce (or acquire) and inject are principally our cash out-of-pocket costs of production, transportation and acquisition, and to pay royalties.

We capitalize, as a development cost, injection costs in fields that are in their development stage, which means we have not yet seen incremental oil production due to the CO_2 injections (i.e., a production response). These capitalized development costs will be included in our unevaluated property costs if there are not already proved tertiary reserves in that field. After we see a production response to the CO_2 injections (i.e., the production stage), injection costs will be expensed as incurred, and any previously deferred unevaluated development costs will become subject to depletion upon recognition of proved tertiary reserves. During

2019, 2018 and 2017, we capitalized $19.1 million, $24.5 million and $25.0 million, respectively, of tertiary injection costs associated with our tertiary projects.

Income Taxes

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we finalize our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets (primarily our enhanced oil recovery credits, business interest expense carryforward, and state net operating loss carryforwards). If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of December 31, 2019, we had tax valuation allowances totaling $77.2 million to reduce the carrying value of deferred tax assets related to our disallowed business interest expense and state deferred tax assets. As of December 31, 2018 and 2017, we had tax valuation allowances totaling $51.1 million to reduce the carrying value of our state deferred income tax assets. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized. A 1% increase in our statutory tax rate would have increased our calculated income tax expense by approximately $3.2 million, $4.1 million and $0.5 million for the years ended December 31, 2019, 2018 and 2017, respectively. See Note 7, *Income Taxes*, to the Consolidated Financial Statements and *Results of Operations – Income Taxes* above for further information concerning our income taxes.

Fair Value Estimates

The FASC defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. It does not require us to make any new fair value measurements, but rather establishes a fair value hierarchy that prioritizes the inputs to the valuation techniques used to measure fair value. Level 1 inputs are given the highest priority in the fair value hierarchy, as they represent observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date, while Level 3 inputs are given the lowest priority, as they represent unobservable inputs that are not corroborated by market data. Valuation techniques that maximize the use of observable inputs are favored. See Note 11, *Fair Value Measurements*, to the Consolidated Financial Statements for disclosures regarding our recurring fair value measurements.

Significant uses of fair value measurements include:

- assessment of impairment of long-lived assets; and
- recorded value of commodity derivative instruments.

Impairment Assessment of Long-Lived Assets

We test long-lived assets that are not subject to our quarterly full cost pool ceiling test for impairment, including a portion of our capitalized CO_2 properties and pipelines, whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The factors we assess to determine if a long-lived asset impairment test is necessary include, among other factors, a significant adverse change in the business climate that could affect the value of a long-lived asset, a significant decrease in the market price of an asset group, a significant adverse change in the extent or manner in which a long-lived asset (asset group) is being used or in its physical condition, or a current-period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset (asset group).

We perform our long-lived asset impairment test by comparing the net carrying costs of our long-lived asset groups to the respective expected future undiscounted net cash flows that are supported by these long-lived assets which include production of our probable and possible oil and natural gas reserves. If the undiscounted net cash flows are below the net carrying costs for an asset group, we must record an impairment loss by the amount, if any, that net carrying costs exceed the fair value of the long-lived asset group. Management assumptions impacting expected future undiscounted net cash flows include market estimates of future commodity prices, projections of estimated reserve quantities, projections of future rates of production, timing and amount of future development and operating costs, projected availability and cost of CO_2, projected recovery factors of tertiary reserves and risk-adjustment factors applied to the net cash flows. We did not record an impairment of long-lived assets during the year ended December 31, 2019.

Commodity Derivative Contracts

Historically, we have entered into oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps, fixed-price swaps enhanced with a sold put, and basis swaps. Our derivative financial instruments are recorded on the balance sheet as either an asset or liability measured at fair value. The valuation methods used to measure the fair values of these assets and liabilities require considerable management judgment and estimates to derive the inputs necessary to determine fair value estimates, such as forward prices for commodities, interest rates, volatility factors and credit worthiness, as well as other relevant economic measures. We do not apply hedge accounting to our commodity derivative contracts under the FASC *Derivatives and Hedging* topic; accordingly, changes in the fair value of these instruments are recognized in earnings instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings. While we may experience more volatility in our net income (loss) than if we were to apply hedge accounting treatment as permitted by the FASC *Derivatives and Hedging* topic, we believe that for us, the benefits associated with applying hedge accounting do not outweigh the cost, time and effort to comply with hedge accounting.

Environmental and Litigation Contingencies

The Company makes judgments and estimates in recording liabilities for contingencies such as environmental remediation or ongoing litigation. Liabilities are recorded when it is both probable that a loss has been incurred and such loss is reasonably estimable. Assessments of liabilities are based on information obtained from independent and in-house experts, loss experience in similar situations, actual costs incurred, and other case-by-case factors. Actual costs can vary from such estimates for a variety of reasons. The costs of environmental remediation or litigation can vary from estimates due to new developments regarding the facts and circumstances of each event, including in the case of environmental remediation, the timing of remediation, our understanding of the environmental impact, remediation methods available, and regulatory requirements, and in the case of litigation, differing interpretations of laws and facts and assessments of damages asserted and/or incurred.

Use of Estimates

See Note 1, *Nature of Operations and Summary of Significant Accounting Policies*, to the Consolidated Financial Statements for a discussion of our use of estimates.

Recent Accounting Pronouncements

See Note 1, *Nature of Operations and Summary of Significant Accounting Policies*, to the Consolidated Financial Statements for a discussion of recent accounting pronouncements.

FORWARD-LOOKING INFORMATION

The data and/or statements contained in this Annual Report on Form 10-K that are not historical facts, including, but not limited to, statements found in the sections entitled "Business and Properties" and "Management's Discussion and Analysis of Financial Condition and Results of Operations," are forward-looking statements, as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, financial forecasts, future hydrocarbon prices and their volatility, current or future liquidity sources or their adequacy to support our anticipated future activities, our ability to refinance or extend the maturities of our long-term indebtedness which matures in 2021 and 2022, possible future write-downs of oil and natural gas reserves, together with assumptions based on current and projected production levels, oil and gas prices and oilfield costs, current or future expectations or estimations of our cash flows or the impact of changes in commodity prices on cash flows, availability of capital, borrowing capacity, price and availability of advantageous commodity derivative contracts or the predicted cash flow benefits therefrom, forecasted capital expenditures, drilling activity or methods, including the timing and location thereof, the nature of any future asset purchases or sales or the timing or proceeds thereof, estimated timing of commencement of CO_2 flooding of particular fields or areas, including Cedar Creek Anticline ("CCA"), or the availability of capital for CCA pipeline construction, or its ultimate cost or date of completion, timing of CO_2 injections and initial production responses in tertiary flooding projects, development activities, finding costs, anticipated future cost savings, capital budgets, interpretation or prediction of formation details, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves and supply and their availability, potential reserves, barrels or percentages of recoverable original oil in place, levels of tariffs or other trade restrictions, the likelihood, timing and impact of increased interest rates, the impact of regulatory rulings or changes, outcomes of pending litigation, prospective legislation affecting the oil and gas industry, environmental regulations, mark-to-market values, the actual or anticipated future drop in worldwide oil demand due to the COVID-19 coronavirus, competition, rates of return, estimated costs, changes in costs, future capital expenditures and overall economics, worldwide economic conditions, the likelihood and extent of an economic slowdown, and other variables surrounding operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "forecast," "to our knowledge," "anticipate," "projected," "preliminary," "should," "assume," "believe," "may" or other words that convey, or are intended to convey, the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates, and assumptions and is subject to a number of risks and uncertainties that could significantly and adversely affect current plans, anticipated actions, the timing of such actions and our financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by us or on our behalf. Among the factors that could cause actual results to differ materially are fluctuations in worldwide oil prices or in U.S. oil prices and consequently in the prices received or demand for our oil and natural gas; evolving political and military tensions in the Middle East; decisions as to production levels and/or pricing by OPEC or production levels by U.S. shale producers in future periods; levels of future capital expenditures; trade disputes and resulting tariffs or international economic sanctions; effects and maturity dates of our indebtedness; success of our risk management techniques; accuracy of our cost estimates; access to and terms of credit in the commercial banking or other debt markets; fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards and remediation costs; disruption of operations and damages from well incidents, hurricanes, tropical storms, forest fires, or other natural occurrences; acquisition risks; requirements for capital or its availability; conditions in the worldwide financial, trade and credit markets; general economic conditions; competition; government regulations, including changes in tax or environmental laws or regulations; and unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or that are otherwise discussed in this annual report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in our other public reports, filings and public statements.

Denbury Resources Inc.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The information required by Item 7A is set forth under *Market Risk Management* in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

Item 8. Financial Statements and Supplementary Information

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Denbury Resources Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Denbury Resources Inc. and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of operations, of changes in stockholders' equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 1 to the consolidated financial statements, the Company has changed the manner in which it accounts for leases in 2019.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The Impact of Proved Oil and Natural Gas Reserves on Net Proved Oil and Natural Gas Properties

The Company's net properties and equipment balance was $4.4 billion as of December 31, 2019, and depreciation, depletion and amortization (DD&A) expense for the year ended December 31, 2019 was $234 million, both of which include proved oil and natural gas properties. As described in Note 1, the Company follows the full cost method of accounting, under which capitalized costs, including production equipment and future development costs, are depleted or depreciated using the unit-of-production method based on proved oil and natural gas reserves as determined by independent petroleum engineers (management's specialists). As disclosed by management, on a quarterly basis, management performs a full cost ceiling impairment test on proved oil and natural gas properties. In 2019, the Company did not have any ceiling test impairments on its proved oil and natural gas properties. Under the ceiling test, the net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as (1) the present value of estimated future net revenues from proved oil and natural gas reserves before future abandonment costs (discounted at 10%), based on the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period prior to the end of a particular reporting period; plus (2) the cost of properties not being amortized; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) related income tax effects. Estimating quantities of proved oil and natural gas reserves is a complex process. It requires interpretations of available technical data and various assumptions, including future production rates, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, and the assumed effect of governmental rules and regulations.

The principal considerations for our determination that performing procedures relating to the impact of proved oil and natural gas reserves on net proved oil and natural gas properties is a critical audit matter are there was significant judgment by management, including the use of specialists, when developing the estimates of proved oil and natural gas reserves. This in turn led to a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating audit evidence related to the significant assumptions used in developing those estimates of proved oil and natural gas reserves, including future production rates and capital expenditures.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved oil and natural gas reserves, the full cost ceiling impairment test, and depletion, depreciation and amortization expense. These procedures also included, among others (i) evaluating the significant assumptions used by management in developing the estimates of proved oil and natural gas reserves, including future production rates and capital expenditures, (ii) testing the full cost ceiling impairment test calculation, and (iii) testing the unit-of-production rate used to calculate DD&A expense. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the estimates of proved oil and natural gas reserves. As a basis for using this work, the specialists' qualifications and objectivity were understood, as well as the methods and assumptions used by the specialists. The procedures performed also included tests of the data used by the specialists and an evaluation of the specialist's findings. Evaluating the significant assumptions relating to the estimates of proved oil and natural gas reserves also involved obtaining evidence to support the reasonableness of the assumptions, including whether the assumptions used were reasonable considering the past performance of the Company, and whether they were consistent with evidence obtained in other areas of the audit.

/s/ PricewaterhouseCoopers LLP
Dallas, Texas
February 26, 2020

We have served as the Company's auditor since 2004.

Denbury Resources Inc.
Consolidated Balance Sheets
(In thousands, except par value and share data)

	December 31, 2019	December 31, 2018
Assets		
Current assets		
Cash and cash equivalents	$ 516	$ 38,560
Accrued production receivable	139,407	125,788
Trade and other receivables, net	18,318	26,970
Derivative assets	11,936	93,080
Other current assets	10,434	11,896
Total current assets	180,611	296,294
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	11,447,680	11,072,209
Unevaluated properties	872,910	996,700
CO_2 properties	1,198,846	1,196,795
Pipelines and plants	2,329,078	2,302,817
Other property and equipment	212,334	250,279
Less accumulated depletion, depreciation, amortization and impairment	(11,688,020)	(11,500,190)
Net property and equipment	4,372,828	4,318,610
Operating lease right-of-use assets	34,099	—
Derivative assets	—	4,195
Other assets	104,329	104,123
Total assets	$ 4,691,867	$ 4,723,222
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 183,832	$ 198,380
Oil and gas production payable	62,869	61,288
Derivative liabilities	8,346	—
Current maturities of long-term debt (including future interest payable of $86,054 and $85,303, respectively – see Note 6)	102,294	105,125
Operating lease liabilities	6,901	—
Total current liabilities	364,242	364,793
Long-term liabilities		
Long-term debt, net of current portion (including future interest payable of $78,860 and $164,914, respectively – see Note 6)	2,232,570	2,664,211
Asset retirement obligations	177,108	174,470
Deferred tax liabilities, net	410,230	309,758
Operating lease liabilities	41,932	—
Other liabilities	53,526	68,213
Total long-term liabilities	2,915,366	3,216,652
Commitments and contingencies (Note 12)		
Stockholders' equity		
Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $.001 par value, 750,000,000 shares authorized; 508,065,495 and 462,355,725 shares issued, respectively	508	462
Paid-in capital in excess of par	2,739,099	2,685,211
Accumulated deficit	(1,321,314)	(1,533,112)
Treasury stock, at cost, 1,652,771 and 1,941,749 shares, respectively	(6,034)	(10,784)
Total stockholders' equity	1,412,259	1,141,777
Total liabilities and stockholders' equity	$ 4,691,867	$ 4,723,222

See accompanying Notes to Consolidated Financial Statements.

Denbury Resources Inc.
Consolidated Statements of Operations
(In thousands, except per share data)

	Year Ended December 31,		
	2019	2018	2017
Revenues and other income			
Oil, natural gas, and related product sales	$ 1,212,020	$ 1,422,589	$ 1,089,666
CO_2 sales and transportation fees	34,142	31,145	26,182
Purchased oil sales	14,198	1,921	3,718
Other income	14,523	17,970	10,220
Total revenues and other income	1,274,883	1,473,625	1,129,786
Expenses			
Lease operating expenses	477,220	489,720	447,799
Transportation and marketing expenses	41,810	43,942	44,064
CO_2 discovery and operating expenses	2,922	2,816	3,099
Taxes other than income	93,752	104,670	87,207
Purchased oil expenses	14,124	1,676	3,304
General and administrative expenses	83,029	71,495	101,806
Interest, net of amounts capitalized of $36,671, $37,079 and $30,762, respectively	81,632	69,688	99,263
Depletion, depreciation, and amortization	233,816	216,449	207,713
Commodity derivatives expense (income)	70,078	(21,087)	77,576
Gain on debt extinguishment	(155,998)	—	—
Other expenses	11,187	84,325	11,455
Total expenses	953,572	1,063,694	1,083,286
Income before income taxes	321,311	409,931	46,500
Income tax provision (benefit)	104,352	87,233	(116,652)
Net income	$ 216,959	$ 322,698	$ 163,152
Net income per common share			
Basic	$ 0.47	$ 0.75	$ 0.42
Diluted	$ 0.45	$ 0.71	$ 0.41
Weighted average common shares outstanding			
Basic	459,524	432,483	390,928
Diluted	510,341	456,169	395,921

See accompanying Notes to Consolidated Financial Statements.

Denbury Resources Inc.
Consolidated Statements of Cash Flows
(In thousands)

	Year Ended December 31,		
	2019	2018	2017
Cash flows from operating activities			
Net income	$ 216,959	$ 322,698	$ 163,152
Adjustments to reconcile net income to cash flows from operating activities			
Depletion, depreciation, and amortization	233,816	216,449	207,713
Deferred income taxes	100,471	103,234	(95,779)
Stock-based compensation	12,470	11,951	15,154
Commodity derivatives expense (income)	70,078	(21,087)	77,576
Receipt (payment) on settlements of commodity derivatives	23,606	(175,248)	(47,795)
Gain on debt extinguishment	(155,998)	—	—
Debt issuance costs and discounts	12,303	6,246	6,191
Other, net	(8,596)	(4,725)	3,112
Changes in assets and liabilities, net of effects from acquisitions			
Accrued production receivable	(13,619)	20,547	(21,398)
Trade and other receivables	9,379	16,094	(4,421)
Other current and long-term assets	7,629	(6,827)	(1,722)
Accounts payable and accrued liabilities	(3,275)	13,008	(24,710)
Oil and natural gas production payable	2,170	(15,300)	(3,997)
Other liabilities	(13,250)	42,645	(5,933)
Net cash provided by operating activities	494,143	529,685	267,143
Cash flows from investing activities			
Oil and natural gas capital expenditures	(262,005)	(316,647)	(262,867)
Acquisitions of oil and natural gas properties	(79)	(541)	(88,886)
CO_2 capital expenditures	(3,154)	(5,878)	(2,159)
Pipelines and plants capital expenditures	(27,319)	(23,108)	(2,540)
Net proceeds from sales of oil and natural gas properties and equipment	10,196	7,762	1,696
Other	12,669	5,136	(2,058)
Net cash used in investing activities	(269,692)	(333,276)	(356,814)
Cash flows from financing activities			
Bank repayments	(925,791)	(1,982,653)	(1,589,000)
Bank borrowings	925,791	1,507,653	1,763,000
Interest payments treated as a reduction of debt	(85,303)	(79,606)	(50,349)
Proceeds from issuance of senior secured notes	—	450,000	—
Cash paid in conjunction with debt exchange	(136,427)	—	—
Repayment or repurchases of senior subordinated notes	—	—	(2,503)
Costs of debt financing	(11,065)	(16,060)	(6,289)
Pipeline financing and capital lease debt repayments	(13,908)	(23,300)	(27,462)
Other	348	(13,486)	1,216
Net cash provided by (used in) financing activities	(246,355)	(157,452)	88,613
Net increase (decrease) in cash, cash equivalents, and restricted cash	(21,904)	38,957	(1,058)
Cash, cash equivalents, and restricted cash at beginning of year	54,949	15,992	17,050
Cash, cash equivalents, and restricted cash at end of year	$ 33,045	$ 54,949	$ 15,992

See accompanying Notes to Consolidated Financial Statements.

Denbury Resources Inc.
Consolidated Statements of Changes in Stockholders' Equity
(Dollar amounts in thousands)

	Common Stock ($.001 Par Value)		Paid-In Capital in Excess of Par	Retained Earnings (Accumulated Deficit)	Treasury Stock (at cost)		
	Shares	Amount			Shares	Amount	Total Equity
Balance – December 31, 2016	402,334,655	$ 402	$ 2,534,670	$ (2,018,989)	3,906,877	$ (47,635)	$ 468,448
Issued or purchased pursuant to stock compensation plans	5,201,854	6	(6)	—	—	—	—
Issued pursuant to directors' compensation plan	12,837	—	—	—	—	—	—
Stock-based compensation	—	—	19,721	—	—	—	19,721
Tax withholding – stock compensation	—	—	—	—	1,550,164	(3,183)	(3,183)
Retirement of treasury stock	(5,000,000)	(5)	(46,557)	—	(5,000,000)	46,562	—
Dividends adjustments	—	—	—	27	—	—	27
Net income	—	—	—	163,152	—	—	163,152
Balance – December 31, 2017	402,549,346	403	2,507,828	(1,855,810)	457,041	(4,256)	648,165
Issued or purchased pursuant to stock compensation plans	4,556,424	4	(4)	—	—	—	—
Issued pursuant to notes conversion	55,249,955	55	161,949	—	—	—	162,004
Stock-based compensation	—	—	15,438	—	—	—	15,438
Tax withholding – stock compensation	—	—	—	—	1,484,708	(6,528)	(6,528)
Net income	—	—	—	322,698	—	—	322,698
Balance – December 31, 2018	462,355,725	462	2,685,211	(1,533,112)	1,941,749	(10,784)	1,141,777
Issued or purchased pursuant to stock compensation plans	9,315,016	9	(9)	—	—	—	—
Issued pursuant to directors' compensation plan	97,537	—	—	—	—	—	—
Issued pursuant to senior subordinated notes exchanges	36,297,217	37	37,409	(5,161)	(1,990,000)	7,270	39,555
Stock-based compensation	—	—	16,488	—	—	—	16,488
Tax withholding – stock compensation	—	—	—	—	1,701,022	(2,520)	(2,520)
Net income	—	—	—	216,959	—	—	216,959
Balance – December 31, 2019	508,065,495	$ 508	$ 2,739,099	$ (1,321,314)	1,652,771	$ (6,034)	$ 1,412,259

See accompanying Notes to Consolidated Financial Statements.

Denbury Resources Inc.
Notes to Consolidated Financial Statements

Note 1. Nature of Operations and Summary of Significant Accounting Policies

Organization and Nature of Operations

Denbury Resources Inc., a Delaware corporation, is an independent oil and natural gas company with operations focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of our properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to CO_2 enhanced oil recovery operations.

Principles of Reporting and Consolidation

The consolidated financial statements herein have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") and include the accounts of Denbury and entities in which we hold a controlling financial interest. Undivided interests in oil and gas joint ventures are consolidated on a proportionate basis. All intercompany balances and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amount of certain assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during each reporting period. Management believes its estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates underlying these financial statements include (1) the fair value of financial derivative instruments; (2) the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties, the related present value of estimated future net cash flows therefrom and the ceiling test; (3) future net cash flow estimates used in the impairment assessment of long-lived assets; (4) the estimated quantities of proved and probable CO_2 reserves used to compute depletion of CO_2 properties; (5) estimated useful lives used to compute depreciation and amortization of long-lived assets; (6) accruals related to oil and natural gas sales volumes and revenues, capital expenditures and lease operating expenses; (7) the estimated costs and timing of future asset retirement obligations; and (8) estimates made in the calculation of income taxes. While management is not aware of any significant revisions to any of its current year-end estimates, there will likely be future revisions to its estimates resulting from matters such as revisions in estimated oil and natural gas volumes, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and natural gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period in which the adjustment occurs.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current year presentation. On the Consolidated Statements of Operations for the years ended December 31, 2018 and 2017, "Purchased oil sales" is a new line item and includes sales related to purchases of oil from third-parties, which were reclassified from "Other income," "Purchased oil expenses" is a new line item and includes expenses related to purchases of oil from third-parties, which were reclassified from "Marketing and plant operating expenses" used in prior reports, and "Transportation and marketing expenses" is a new line item, previously captioned "Marketing and plant operating expenses," but adjusted to exclude both expenses related to plant operating expenses, which were reclassified to "Other expenses," and also purchases of oil from third parties. Such reclassifications had no impact on our reported total revenues, expenses, net income, current assets, total assets, current liabilities, total liabilities or stockholders' equity.

Cash, Cash Equivalents, and Restricted Cash

We consider all highly liquid investments to be cash equivalents if they have maturities of three months or less at the date of purchase. The following table provides a reconciliation of cash, cash equivalents, and restricted cash as reported within the Consolidated Balance Sheets to "Cash, cash equivalents, and restricted cash at end of year" as reported within the Consolidated Statements of Cash Flows:

	December 31,	
In thousands	2019	2018
Cash and cash equivalents	$ 516	$ 38,560
Restricted cash included in other assets	32,529	16,389
Total cash, cash equivalents, and restricted cash shown in the Consolidated Statements of Cash Flows	$ 33,045	$ 54,949

Amounts included in restricted cash included in "Other assets" in the accompanying Consolidated Balance Sheets represent escrow accounts that are legally restricted for certain of our asset retirement obligations.

Oil and Natural Gas Properties

Capitalized Costs. We follow the full cost method of accounting for oil and natural gas properties. Under this method, all costs related to the acquisition, exploration and development of oil and natural gas reserves are capitalized and accumulated in a single cost center representing our activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and nonproductive wells, capitalized interest on qualifying projects, and general and administrative expenses directly related to exploration and development activities, and do not include any costs related to production, general corporate overhead or similar activities. We assign the purchase price of oil and natural gas properties we acquire to proved and unevaluated properties based on the estimated fair values as defined in the Financial Accounting Standards Board Codification ("FASC") *Fair Value Measurement* topic. Proceeds received from disposals are credited against accumulated costs except when the sale represents a significant disposal of reserves, in which case a gain or loss would be recognized. A disposal of 25% or more of our proved reserves would be considered significant.

Depletion and Depreciation. The costs capitalized, including production equipment and future development costs, are depleted or depreciated using the unit-of-production method, based on proved oil and natural gas reserves as determined by independent petroleum engineers. Oil and natural gas reserves are converted to equivalent units on a basis of 6,000 cubic feet of natural gas to one barrel of crude oil.

Under full cost accounting, we may exclude certain unevaluated costs from the amortization base pending determination of whether proved reserves can be assigned to such properties. The costs classified as unevaluated are transferred to the full cost amortization base as the properties are developed, tested and evaluated. At least annually, we test these assets for impairment based on an evaluation of management's expectations of future pricing, evaluation of lease expiration terms, and planned project development activities. As a result of this analysis, we recognized impairments of our unevaluated costs totaling $18.2 million and $21.4 million during the years ended December 31, 2019 and 2017, respectively, whereby these costs were transferred to the full cost amortization base. We did not record any impairments of our unevaluated costs during the year ended December 31, 2018.

Write-Down of Oil and Natural Gas Properties. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as (1) the present value of estimated future net revenues from proved oil and natural gas reserves before future abandonment costs (discounted at 10%), based on the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period prior to the end of a particular reporting period; plus (2) the cost of properties not being amortized; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) related income tax effects. Our future net revenues from proved oil and natural gas reserves are not reduced for development costs related to the cost of drilling for and developing CO_2 reserves nor those related to the cost of constructing CO_2 pipelines, as we do not have to incur additional costs to develop the proved oil and natural gas reserves. Therefore, we include in the ceiling test, as a reduction of future net revenues, that portion of our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves. The fair value of our oil and natural gas derivative contracts is not included in the ceiling test, as we do not designate these contracts as hedge instruments for accounting purposes. The cost center ceiling test is prepared quarterly. We did not record any ceiling test write-downs during 2017, 2018 or 2019.

Joint Interest Operations. Substantially all of our oil and natural gas exploration and production activities are conducted jointly with others. These financial statements reflect only our proportionate interest in such activities, and any amounts due from other partners are included in trade receivables.

Tertiary Injection Costs. Our tertiary operations are conducted in reservoirs that have already produced significant amounts of oil over many years; however, in accordance with the Securities and Exchange Commission ("SEC") rules and regulations for recording proved reserves, we cannot recognize proved reserves associated with enhanced recovery techniques, such as CO_2 injection, until we can demonstrate production resulting from the tertiary process or unless the field is analogous to an existing flood.

We capitalize, as a development cost, injection costs in fields that are in their development stage, which means we have not yet seen incremental oil production due to the CO_2 injections (i.e., a production response). These capitalized development costs are included in our unevaluated property costs if there are not already proved tertiary reserves in that field. After we see a production response to the CO_2 injections (i.e., the production stage), injection costs are expensed as incurred, and once proved reserves are recognized, previously deferred unevaluated development costs become subject to depletion.

CO_2 Properties

We own and produce CO_2 reserves, a non-hydrocarbon resource, that are used in our tertiary oil recovery operations on our own behalf and on behalf of other interest owners in enhanced recovery fields, with a portion sold to third-party industrial users. We record revenue from our sales of CO_2 to third parties when it is produced and sold. Expenses related to the production of CO_2 are allocated between volumes sold to third parties and volumes consumed internally that are directly related to our tertiary production. The expenses related to third-party sales are recorded in "CO_2 discovery and operating expenses," and the expenses related to internal use are recorded in "Lease operating expenses" in the Consolidated Statements of Operations or are capitalized as oil and natural gas properties in our Consolidated Balance Sheets, depending on the stage of the tertiary flood that is receiving the CO_2 (see *Tertiary Injection Costs* above for further discussion).

Costs incurred to search for CO_2 are expensed as incurred until proved or probable reserves are established. Once proved or probable reserves are established, costs incurred to obtain those reserves are capitalized and classified as "CO_2 properties" on our Consolidated Balance Sheets. Capitalized CO_2 costs are aggregated by geologic formation and depleted on a unit-of-production basis over proved and probable reserves.

Pipelines and Plants

CO_2 used in our tertiary floods is transported to our fields through CO_2 pipelines. Costs of CO_2 pipelines under construction are not depreciated until the pipelines are placed into service. Pipelines are depreciated on a straight-line basis over their estimated useful lives, which range from 20 to 50 years. Capitalized costs include \$117.6 million of CO_2 pipelines as of December 31, 2019, that were either under construction or had not been placed into service and therefore, were not subject to depreciation during 2019.

Property and Equipment – Other

Other property and equipment, which includes furniture and fixtures, vehicles, and computer equipment and software, is depreciated principally on a straight-line basis over each asset's estimated useful life. Vehicles and furniture and fixtures are generally depreciated over a useful life of five to ten years, and computer equipment and software are generally depreciated over a useful life of three to five years. Leasehold improvements are amortized over the shorter of the estimated useful life or the remaining lease term.

Maintenance and repair costs that do not extend the useful life of the property or equipment are charged to expense as incurred.

Intangible Assets

Our intangible assets subject to amortization primarily consist of amounts assigned in purchase accounting to a CO_2 purchase contract with ConocoPhillips to offtake CO_2 from the Lost Cabin gas plant in Wyoming and are included in our Consolidated Balance Sheets under the caption “Other assets.” We amortize the CO_2 contract intangible asset on a straight-line basis over the contract term. Total amortization expense for our intangible assets was $2.4 million, $2.4 million and $2.4 million during the years ended December 31, 2019, 2018 and 2017. The following table summarizes the carrying value of our intangible assets as of December 31, 2019 and 2018:

	December 31,	
In thousands	2019	2018
Intangible asset value	$ 37,608	$ 37,848
Accumulated amortization	(15,502)	(13,074)
Net book value	$ 22,106	$ 24,774

As of December 31, 2019, our estimated amortization expense for our intangible assets subject to amortization over the next five years is as follows:

In thousands	
2020	$ 2,420
2021	2,420
2022	2,420
2023	2,420
2024	2,420

Impairment Assessment of Long-Lived Assets

The portion of our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves is included in the full cost pool ceiling test as a reduction to future net revenues. The remaining net capitalized costs that are not included in the full cost pool ceiling test, and related intangible assets, are subject to long-lived asset impairment testing whenever events or changes in circumstances indicate that the carrying value may not be recoverable.

We perform our long-lived asset impairment test by comparing the net carrying costs of our long-lived asset groups to the respective expected future undiscounted net cash flows that are supported by these long-lived assets which include production of our probable and possible oil and natural gas reserves. If the undiscounted net cash flows are below the net carrying costs for an asset group, we must record an impairment loss by the amount, if any, that net carrying costs exceed the fair value of the long-lived asset group. We did not record an impairment of long-lived assets during the year ended December 31, 2019.

Asset Retirement Obligations

In general, our future asset retirement obligations relate to future costs associated with plugging and abandoning our oil, natural gas and CO_2 wells, removing equipment and facilities from leased acreage, and returning land to its original condition. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using our credit-adjusted-risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset. Revisions to estimated retirement obligations will result in an adjustment to the related capitalized asset and corresponding liability. If the liability for an oil or natural gas well is settled for an amount other than the recorded amount, the difference is recorded to the full cost pool, unless significant.

Asset retirement obligations are estimated at the present value of expected future net cash flows. We utilize unobservable inputs in the estimation of asset retirement obligations that include, but are not limited to, costs of labor and materials, profits on costs of labor and materials, the effect of inflation on estimated costs, and the discount rate. Accordingly, asset retirement obligations are considered a Level 3 measurement under the FASC *Fair Value Measurement* topic.

Commodity Derivative Contracts

We utilize oil and natural gas derivative contracts to mitigate our exposure to commodity price risk associated with our future oil and natural gas production. These derivative contracts have historically consisted of options, in the form of price floors, collars, three-way collars, fixed-price swaps, fixed-price swaps enhanced with a sold put, and basis swaps. Our derivative financial instruments, other than any derivative instruments that are designated under the “normal purchase normal sale” exclusion, are recorded on the balance sheet as either an asset or a liability measured at fair value. We do not apply hedge accounting to our commodity derivative contracts; accordingly, changes in the fair value of these instruments are recognized in “Commodity derivatives expense (income)” in our Consolidated Statements of Operations in the period of change.

Concentrations of Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents, trade and accrued production receivables, and the derivative instruments discussed above. Our cash equivalents represent high-quality securities placed with various investment-grade institutions. This investment practice limits our exposure to concentrations of credit risk. Our trade and accrued production receivables are dispersed among various customers and purchasers; therefore, concentrations of credit risk are limited. We evaluate the credit ratings of our purchasers, and if customers are considered a credit risk, letters of credit are the primary security obtained to support lines of credit. We attempt to minimize our credit risk exposure to the counterparties of our oil and natural gas derivative contracts through formal credit policies, monitoring procedures and diversification. All of our derivative contracts are with parties that are lenders under our senior secured bank credit facility (or affiliates of such lenders). There are no margin requirements with the counterparties of our derivative contracts.

Oil and natural gas sales are made on a day-to-day basis or under short-term contracts at the current area market price. We would not expect the loss of any purchaser to have a material adverse effect upon our operations. For the year ended December 31, 2019, three purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (32%), Hunt Crude Oil Supply Company (11%) and Sunoco Inc. (11%). For the year ended December 31, 2018, two purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (24%) and Hunt Crude Oil Supply Company (10%). For the year ended December 31, 2017, two purchasers accounted for 10% or more of our oil and natural gas revenues: Plains Marketing LP (22%) and Marathon Petroleum Company (10%).

Other Receivables

During 2018, we recorded a $16.9 million impairment of a loan related to a proposed plant in the Gulf Coast that would potentially supply CO_2 to Denbury, due to uncertainties of the project achieving financial close. The impairment was included within “Other expenses” in our Consolidated Statements of Operations for the year ended December 31, 2018.

Income Taxes

Income taxes are accounted for using the asset and liability method, under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at year end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement.

Net Income per Common Share

Basic net income per common share is computed by dividing the net income attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner, but includes the impact of potentially dilutive securities. Potentially dilutive securities consist of nonvested restricted stock, nonvested performance-based equity awards, and shares into which our convertible senior notes are convertible.

The following table sets forth the reconciliations of net income and weighted average shares used for purposes of calculating basic and diluted net income per common share for the periods indicated:

	Year Ended December 31,		
In thousands	2019	2018	2017
Numerator			
Net income – basic	$ 216,959	$ 322,698	$ 163,152
Effect of potentially dilutive securities			
Interest expensed on convertible senior notes including amortization of discount, net of tax	14,134	539	49
Net income – diluted	$ 231,093	$ 323,237	$ 163,201
Denominator			
Weighted average common shares outstanding – basic	459,524	432,483	390,928
Effect of potentially dilutive securities			
Restricted stock and performance-based equity awards	2,396	6,500	2,242
Convertible senior notes(1)	48,421	17,186	2,751
Weighted average common shares outstanding – diluted	510,341	456,169	395,921

(1) For the year ended December 31, 2019, shares shown under "convertible senior notes" represent the prorated portion of the approximately 90.9 million shares of the Company's common stock issuable upon full conversion of our convertible senior notes which were issued on June 19, 2019 (see Note 6, *Long-Term Debt – 2019 Debt Reduction Transactions*).

Basic weighted average common shares exclude shares of nonvested restricted stock. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income per common share (although time-vesting restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares, the nonvested restricted stock and performance-based equity awards are included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, and for the shares underlying the convertible senior notes as if the convertible senior notes were converted at the earliest date outstanding during the respective periods. In April and May 2018, all of the then outstanding 3½% Convertible Senior Notes due 2024 and 5% Convertible Senior Notes due 2023 (the "2023 Convertible Senior Notes") converted into shares of Denbury common stock, resulting in the issuance of 55.2 million shares of our common stock upon conversion. These shares have been included in basic weighted average common shares outstanding beginning on the date of conversion. See Note 6, *Long-Term Debt*, for further discussion.

The following securities could potentially dilute earnings per share in the future, but were excluded from the computation of diluted net income per share, as their effect would have been antidilutive:

	Year Ended December 31,		
In thousands	2019	2018	2017
Stock appreciation rights	2,027	2,743	4,512
Restricted stock and performance-based equity awards	5,505	1,234	5,645

Environmental and Litigation Contingencies

The Company makes judgments and estimates in recording liabilities for contingencies such as environmental remediation or ongoing litigation. Liabilities are recorded when it is both probable that a loss has been incurred and such loss is reasonably estimable. Assessments of liabilities are based on information obtained from independent and in-house experts, loss experience in similar situations, actual costs incurred, and other case-by-case factors. Any related insurance recoveries are recognized in our financial statements during the period received or at the time receipt is determined to be virtually certain.

Recent Accounting Pronouncements

Recently Adopted

Leases. Effective January 1, 2019, we adopted Financial Accounting Standards Board ("FASB") Accounting Standards Update ("ASU") 2016-02, *Leases* ("ASU 2016-02"), and ASU 2018-01, *Leases (Topic 842) – Land Easement Practical Expedient for Transition to Topic 842*, using the modified retrospective method with an application date of January 1, 2019. ASU 2016-02 does not apply to mineral leases or leases that convey the right to explore for or use the land on which oil, natural gas, and similar natural resources are contained. We elected the practical expedients provided in the new ASUs that allow historical lease classification of existing leases, allow lease and non-lease components to be combined, and carry forward our accounting treatment for existing land easement agreements. The adoption of the new standards resulted in the recognition of $39.1 million of lease right-of-use assets and $55.8 million of operating lease liabilities ($16.7 million of which related to previously-existing lease obligations) as of January 1, 2019, in our Consolidated Balance Sheets, but did not materially impact our results of operations and had no impact on our cash flows. The additional lease right-of-use assets and operating lease liabilities recorded on our balance sheet primarily related to our leases for office space, as the accounting for our financing leases and pipeline financings was relatively unchanged.

Not Yet Adopted

Financial Instruments – Credit Losses. In June 2016, the FASB issued ASU 2016-13, *Financial Instruments – Credit Losses* ("ASU 2016-13"). ASU 2016-13 changes the impairment model for most financial assets and certain other instruments, including trade and other receivables, and requires the use of a new forward-looking expected loss model that will result in the earlier recognition of allowances for losses. The amendments in this ASU are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, and early adoption is permitted. Entities must adopt the amendment using a modified retrospective approach to the first reporting period in which the guidance is effective. We intend to adopt the standard using a modified retrospective approach with an application date of January 1, 2020. The adoption of ASU 2016-13 is not expected to have a material effect on our consolidated financial statements.

Fair Value Measurement. In August 2018, the FASB issued ASU 2018-13, *Fair Value Measurement* (Topic 820) *– Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurements* ("ASU 2018-13"). ASU 2018-13 adds, modifies, or removes certain disclosure requirements for recurring and nonrecurring fair value measurements based on the FASB's consideration of costs and benefits. The amendments in this ASU are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, and early adoption is permitted. Entities must adopt the amendments on changes in unrealized gains and losses for Level 3 fair value measurements, the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements, and the narrative description of measurement uncertainty prospectively, and all other amendments should be applied retrospectively to all periods presented. We plan to adopt the standard with an application date of January 1, 2020. The adoption of ASU 2018-13 is not expected to have a material effect on our consolidated financial statements but may require enhanced footnote disclosures.

Note 2. Revenue Recognition

We record revenue in accordance with FASC Topic 606, *Revenue from Contracts with Customers*. The core principle of FASC Topic 606 is that an entity should recognize revenue for the transfer of goods or services equal to the amount of consideration that it expects to be entitled to receive for those goods or services. This principle is achieved through applying a five-step process for customer contract revenue recognition:

Denbury Resources Inc.
Notes to Consolidated Financial Statements

- Identify the contract or contracts with a customer – We derive the majority of our revenues from oil and natural gas sales contracts and CO_2 sales and transportation contracts. The contracts specify each party's rights regarding the goods or services to be transferred and contain commercial substance as they impact our financial statements. A high percentage of our receivables balance is current, and we have not historically entered into contracts with counterparties that pose a credit risk without requiring adequate economic protection to ensure collection.

- Identify the performance obligations in the contract – Each of our revenue contracts specify a volume per day, or production from a lease designated in the contract (a distinct good), to be delivered at the delivery point over the term of the contract (the identified performance obligation). The customer takes delivery and physical possession of the product at the delivery point, which generally is also the point at which title transfers and the customer obtains the risks and rewards of ownership (the identified performance obligation is satisfied).

- Determine the transaction price – Typically, our oil and natural gas contracts define the price as a formula price based on the average market price, as specified on set dates each month, for the specific commodity during the month of delivery. Certain of our CO_2 contracts define the price as a fixed contractual price adjusted to an inflation index to reflect market pricing. Given the industry practice to invoice customers the month following the month of delivery and our high probability of collection of payment, no significant financing component is included in our contracts.

- Allocate the transaction price to the performance obligations in the contract – The majority of our revenue contracts are short-term, with terms of one year or less, to which we have applied the practical expedient permitted under the standard eliminating the requirement to disclose the transaction price allocated to remaining performance obligations. In limited instances, we have revenue contracts with terms greater than one year; however, the future delivery volumes are wholly unsatisfied as they represent separate performance obligations with variable consideration. We utilized the practical expedient which eliminates the requirement to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to wholly unsatisfied performance obligations. As there is only one performance obligation associated with our contracts, no allocation of the transaction price is necessary.

- Recognize revenue when, or as, we satisfy a performance obligation – Once we have delivered the volume of commodity to the delivery point and the customer takes delivery and possession, we are entitled to payment and we invoice the customer for such delivered production. Payment under most oil and CO_2 contracts is made within a month following product delivery and for natural gas and NGL contracts is generally made within two months following delivery. Timing of revenue recognition may differ from the timing of invoicing to customers; however, as the right to consideration after delivery is unconditional based on only the passage of time before payment of the consideration is due, upon delivery we record a receivable in "Accrued production receivable" in our Consolidated Balance Sheets, which was $139.4 million and $125.8 million as of December 31, 2019 and December 31, 2018, respectively.

In addition to revenues from oil and natural gas sales contracts and CO_2 sales and transportation contracts, the Company enters into purchase transactions with third parties and separate sale transactions with third parties in the Gulf Coast region. Revenues and expenses from these transactions are presented on a gross basis, as we act as a principal in the transaction by assuming control of the commodities purchased and the responsibility to deliver the commodities sold. Revenue is recognized when control transfers to the purchaser at the delivery point based on the price received from the purchaser.

Disaggregation of Revenue

The following table summarizes our revenues by product type for the years ended December 31, 2019, 2018 and 2017:

	Year Ended December 31,		
In thousands	2019	2018	2017
Oil sales	$ 1,205,083	$ 1,412,358	$ 1,079,703
Natural gas sales	6,937	10,231	9,963
CO_2 sales and transportation fees	34,142	31,145	26,182
Purchased oil sales	14,198	1,921	3,718
Total revenues	$ 1,260,360	$ 1,455,655	$ 1,119,566

Denbury Resources Inc.
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Note 3. Leases

We evaluate contracts for leasing arrangements at inception. We lease office space, equipment, and vehicles that have non-cancelable lease terms. Currently, our outstanding leases have remaining terms up to 6 years, with certain land leases having remaining terms up to 50 years. Leases with a term of 12 months or less are not recorded on our balance sheet. During the third quarter of 2019, we exercised the early buyout option on our remaining finance leases. The table below reflects our operating lease right-of-use assets and operating lease liabilities, which primarily consists of our office leases:

In thousands	December 31, 2019
Operating leases	
Operating lease right-of-use assets	$ 34,099
Operating lease liabilities - current	$ 6,901
Operating lease liabilities - long-term	41,932
Total operating lease liabilities	$ 48,833

The majority of our leases contain renewal options, typically exercisable at our sole discretion. We record right-of-use assets and liabilities based on the present value of lease payments over the initial lease term, unless the option to extend the lease is reasonably certain, and utilize our incremental borrowing rate based on information available at the lease commencement date. The following weighted average remaining lease terms and discount rates related to our outstanding operating leases:

	December 31, 2019
Weighted average remaining lease term	5.7 years
Weighted average discount rate	6.7%

Lease costs for operating leases or leases with a term of 12 months or less are recognized on a straight-line basis over the lease term. For finance leases, interest on the lease liability and the amortization of the right-of-use asset are recognized separately, with the depreciable life reflective of the expected lease term. We have subleased part of the office space included in our operating leases. We expect to receive a total of approximately $10.4 million for 2020 through 2025 under our sublease agreements. The following table summarizes the components of lease costs and sublease income:

In thousands	Income Statement	Year Ended December 31, 2019
Operating lease cost	General and administrative expenses	$ 8,924
	Lease operating expenses	58
	CO_2 discovery and operating expenses	5
		$ 8,987
Finance lease cost		
Amortization of right-of-use assets	Depletion, depreciation, and amortization	$ 1,188
Interest on lease liabilities	Interest expense	40
Total finance lease cost		$ 1,228
Sublease income	General and administrative expenses	$ 4,127

Denbury Resources Inc.
Notes to Consolidated Financial Statements

Our statement of cash flows included the following activity related to our operating and finance leases:

In thousands	Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities	
Operating cash flows from operating leases	$ 10,995
Operating cash flows from interest on finance leases	40
Financing cash flows from finance leases	1,275
Right-of-use assets obtained in exchange for lease obligations	
Operating leases	415
Finance leases	—

The following table summarizes by year the maturities of our minimum lease payments as of December 31, 2019, but excludes future sublease receipts associated with sublease contracts we have for a portion of these operating leases:

In thousands	Operating Leases
2020	$ 9,934
2021	10,056
2022	10,259
2023	10,300
2024	10,317
Thereafter	8,287
Total minimum lease payments	59,153
Less: Amount representing interest	(10,320)
Present value of minimum lease payments	$ 48,833

The following table summarizes by year the remaining non-cancelable future payments under our leases, as accounted for under previous accounting guidance under FASC Topic 840, *Leases*, as of December 31, 2018:

In thousands	Operating Leases
2019	$ 10,690
2020	9,776
2021	10,007
2022	10,223
2023	10,262
Thereafter	18,169
Total minimum lease payments	$ 69,127

Denbury Resources Inc.
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Note 4. Asset Retirement Obligations

The following table summarizes the changes in our asset retirement obligations for the years ended December 31, 2019 and 2018:

In thousands	Year Ended December 31, 2019	2018
Beginning asset retirement obligations	$ 176,585	$ 166,310
Liabilities incurred and assumed during period	4,354	2,201
Revisions in estimated retirement obligations	9,206	2,298
Liabilities settled and sold during period	(24,342)	(9,481)
Accretion expense	15,957	15,257
Ending asset retirement obligations	181,760	176,585
Less: current asset retirement obligations(1)	(4,652)	(2,115)
Long-term asset retirement obligations	$ 177,108	$ 174,470

(1) Included in "Accounts payable and accrued liabilities" in our Consolidated Balance Sheets.

Liabilities assumed relate to minor acquisitions, with liabilities incurred generally relating to wells and facilities.

We have escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $53.4 million and $42.1 million as of December 31, 2019 and 2018, respectively. These balances are primarily invested in U.S. Treasury bonds, recorded at amortized cost, and money market accounts, which investments are included in "Other assets" in our Consolidated Balance Sheets. A portion of these investments are included in cash, cash equivalents, and restricted cash balances on our Consolidated Statements of Cash Flows (see Note 1, *Nature of Operations and Summary of Significant Accounting Policies – Cash, Cash Equivalents, and Restricted Cash*). The carrying value of these investments approximates their estimated fair market value as of December 31, 2019 and 2018.

Note 5. Unevaluated Property

A summary of the unevaluated property costs excluded from oil and natural gas properties being amortized at December 31, 2019, and the year in which the costs were incurred follows:

	December 31, 2019				
	Costs Incurred During:				
In thousands	2019	2018	2017	2016 and Prior	Total
Property acquisition costs	$ —	$ —	$ 8,527	$ 572,930	$ 581,457
Exploration and development	3,522	1,862	3,175	108,268	116,827
Capitalized interest	31,489	27,013	23,134	92,990	174,626
Total	$ 35,011	$ 28,875	$ 34,836	$ 774,188	$ 872,910

Our property acquisition costs for 2016 and prior were primarily related to the fair value allocated to the purchase of interests in the Cedar Creek Anticline ("CCA") and Hartzog Draw, as well as CO_2 tertiary potential at Conroe Field. Exploration and development costs shown as unevaluated properties are primarily associated with our tertiary oil fields that are under development but did not have proved reserves at December 31, 2019. The most significant development costs incurred during each period relate to development in preparation for the CO_2 floods at Webster, Conroe, and CCA fields. We have not yet recognized proved tertiary reserves in these fields.

Costs are transferred into the amortization base on an ongoing basis as projects are evaluated and proved reserves established or impairment determined. We review the excluded properties for impairment at least annually. We currently estimate that evaluation of the majority of these properties and the inclusion of their costs in the amortization base is expected to be completed within five to ten years. Until we are able to determine whether there are any proved reserves attributable to the above costs, we are not able to assess the future impact on the amortization rate of the full cost pool.

Note 6. Long-Term Debt

The table below reflects long-term debt and capital lease obligations outstanding as of December 31, 2019 and 2018:

	December 31,	
In thousands	2019	2018
Senior Secured Bank Credit Agreement	$ —	$ —
9% Senior Secured Second Lien Notes due 2021	614,919	614,919
9¼% Senior Secured Second Lien Notes due 2022	455,668	455,668
7¾% Senior Secured Second Lien Notes due 2024	531,821	—
7½% Senior Secured Second Lien Notes due 2024	20,641	450,000
6⅜% Convertible Senior Notes due 2024	245,548	—
6⅜% Senior Subordinated Notes due 2021	51,304	203,545
5½% Senior Subordinated Notes due 2022	58,426	314,662
4⅝% Senior Subordinated Notes due 2023	135,960	307,978
Pipeline financings	167,439	180,073
Capital lease obligations	—	5,362
Total debt principal balance	2,281,726	2,532,207
Debt discount(1)	(101,767)	—
Future interest payable(2)	164,914	250,218
Debt issuance costs	(10,009)	(13,089)
Total debt, net of debt issuance costs and discount	2,334,864	2,769,336
Less: current maturities of long-term debt(3)	(102,294)	(105,125)
Long-term debt and capital lease obligations	$ 2,232,570	$ 2,664,211

(1) Consists of discounts related to the issuance during June 2019 of our new 7¾% Senior Secured Second Lien Notes due 2024 (the "7¾% Senior Secured Notes") and new 6⅜% Convertible Senior Notes due 2024 (the "2024 Convertible Senior Notes") of $27.0 million and $74.8 million, respectively (see *2019 Debt Reduction Transactions* below) as of December 31, 2019.
(2) Future interest payable represents most of the interest due over the terms of our 9% Senior Secured Second Lien Notes due 2021 (the "2021 Senior Secured Notes") and 9¼% Senior Secured Second Lien Notes due 2022 (the "2022 Senior Secured Notes") and has been accounted for as debt in accordance with FASC 470-60, *Troubled Debt Restructuring by Debtors*.
(3) Our current maturities of long-term debt as of December 31, 2019 include $86.1 million of future interest payable related to the 2021 Senior Secured Notes and 2022 Senior Secured Notes that is due within the next twelve months.

The ultimate parent company in our corporate structure, Denbury Resources Inc. ("DRI"), is the sole issuer of all our outstanding senior secured, convertible senior, and senior subordinated notes. DRI has no independent assets or operations. Each of the subsidiary guarantors of such notes is 100% owned, directly or indirectly, by DRI, and the guarantees of the notes are full and unconditional and joint and several; any subsidiaries of DRI that are not subsidiary guarantors of such notes are minor subsidiaries.

Senior Secured Bank Credit Facility

In December 2014, we entered into an Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders party thereto (as amended, the "Bank Credit Agreement"). The Bank Credit Agreement is a senior secured revolving credit facility with a maturity date of December 9, 2021, provided that the maturity date may occur earlier (February 12, 2021, May 14, 2021 or August 13, 2021) if the 2021 Senior Secured Notes due in May 2021 or 6⅜% Senior Subordinated Notes due in August 2021 (the "2021 Senior Subordinated Notes"), respectively, are not repaid or refinanced by each of their respective maturity dates. As of December 31, 2019, the borrowing base and lender commitments for the revolving credit facility were $615 million, and scheduled redeterminations of the borrowing base are to occur semiannually in May and

November of each year, with the next such redetermination being scheduled for May 2020. If our outstanding debt under the Bank Credit Agreement were to ever exceed the borrowing base, we would be required to repay the excess amount over a period not to exceed six months. Under the Bank Credit Agreement, letters of credit are available in an aggregate amount not to exceed $100 million, which may be increased at the sole discretion of the administrative agent, and short-term swingline loans are available in an aggregate amount not to exceed $25 million, each subject to the available commitments under the Bank Credit Agreement. The Bank Credit Agreement is guaranteed jointly and severally by each subsidiary of DRI that is 100% owned, directly or indirectly, by DRI and is secured by (1) a significant portion of our proved oil and natural gas properties held through DRI's restricted subsidiaries; (2) the pledge of equity interests of such subsidiaries; (3) a pledge of commodity derivative agreements of DRI and such subsidiaries (as applicable); and (4) a pledge of deposit accounts, securities accounts and commodity accounts of DRI and such subsidiaries (as applicable).

The Bank Credit Agreement limits our ability to, among other things, incur and repay indebtedness; grant liens; engage in certain mergers, consolidations, liquidations and dissolutions; engage in sales of assets; make acquisitions and investments; make distributions and dividends; and enter into commodity derivative agreements, in each case subject to customary exceptions.

The Bank Credit Agreement contains certain financial performance covenants through the maturity of the facility, including the following:

- A Consolidated Total Debt to Consolidated EBITDAX financial maintenance covenant, with such ratio not to exceed 5.25 to 1.0 through December 31, 2020 and 4.50 to 1.0 thereafter;
- A consolidated senior secured debt to consolidated EBITDAX covenant, with such ratio not to exceed 2.5 to 1.0. Only debt under our Bank Credit Agreement is considered consolidated senior secured debt for purposes of this ratio;
- A minimum permitted ratio of consolidated EBITDAX to consolidated interest charges of 1.25 to 1.0; and
- A requirement to maintain a current ratio (i.e., Consolidated Current Assets to Consolidated Current Liabilities) of 1.0 to 1.0.

For purposes of computing the current ratio per the Bank Credit Agreement, Consolidated Current Assets exclude the current portion of derivative assets but include borrowing base availability under the senior secured bank credit facility, and Consolidated Current Liabilities exclude the current portion of derivative liabilities as well as the current portions of long-term indebtedness outstanding.

As of December 31, 2019, (1) loans under the Bank Credit Agreement were subject to varying rates of interest based on either (a) for ABR Loans, a base rate determined under the Bank Credit Agreement (the "ABR") plus an applicable margin ranging from 1.75% to 2.75% per annum, or (b) for LIBOR Loans, the LIBOR rate plus an applicable margin ranging from 2.75% to 3.75% per annum (capitalized terms as defined in the Bank Credit Agreement) and (2) the undrawn portion of the aggregate lender commitments under the Bank Credit Agreement was subject to a commitment fee of 0.50%. As of December 31, 2019, we had no outstanding borrowings, $87.2 million of letters of credit outstanding and were in compliance with all debt covenants under the Bank Credit Agreement.

The above description of our Bank Credit Agreement is qualified by the express language and defined terms contained in the Bank Credit Agreement and the amendments thereto, each of which are filed as exhibits to our periodic reports filed with the SEC.

2019 Debt Reduction Transactions

During the third quarter of 2019, we repurchased $11.0 million in aggregate principal amount of our then outstanding 5½% Senior Subordinated Notes due 2022 (the "2022 Senior Subordinated Notes") in open market transactions for a total purchase price of $5.3 million, excluding accrued interest. Additionally, during the fourth quarter of 2019, we repurchased principally through exchanges an additional $25.3 million in aggregate principal amount of our then outstanding 2022 Senior Subordinated Notes and $75.7 million in aggregate principal amount of our then outstanding 4⅝% Senior Subordinated Notes due 2023 (the "2023 Senior Subordinated Notes") for $11.2 million in cash and issuance of 38.3 million shares of the Company's common stock. In connection with these transactions, we recognized a $55.5 million gain on debt extinguishment, net of unamortized debt issuance costs written off, during the year ended December 31, 2019, in our Consolidated Statements of Operations.

During June 2019, in a series of debt exchanges, we extended the maturities of our outstanding long-term debt and reduced the amount of our outstanding debt principal. As part of these transactions, holders exchanged a total of $468.4 million aggregate principal amount of our then outstanding senior subordinated notes for $102.6 million aggregate principal amount of new 7¾% Senior Secured Notes, $245.5 million aggregate principal amount of new 2024 Convertible Senior Notes and $120.0 million of cash. The exchanged senior subordinated notes consisted of $152.2 million aggregate principal amount of our 2021 Senior Subordinated Notes, $219.9 million aggregate principal amount of our 2022 Senior Subordinated Notes and $96.3 million aggregate principal amount of our 2023 Senior Subordinated Notes. In addition, holders also exchanged $425.4 million of 7½% Senior Secured Second Lien Notes due 2024 (the "7½% Senior Secured Notes") for $425.4 million aggregate principal amount of 7¾% Senior Secured Notes. In July 2019, holders exchanged an additional $4.0 million aggregate principal amount of 7½% Senior Secured Notes for $3.8 million aggregate principal amount of 7¾% Senior Secured Notes. As a result, we recognized a noncash gain on debt extinguishment, net of transaction costs, totaling $100.5 million for the year ended December 31, 2019, in our Consolidated Statements of Operations.

In accordance with FASC 470-50, *Modifications and Extinguishments*, the June 2019 exchange of our existing senior subordinated notes was accounted for as a debt extinguishment. Therefore, our new 7¾% Senior Secured Notes and new 2024 Convertible Senior Notes were recorded on our balance sheet at fair market value based upon initial trading prices following their issuance, resulting in a discount to their principal amount of $22.6 million and $79.9 million, respectively. These debt discounts will be amortized as interest expense over the terms of these notes.

Separately, the June 2019 exchange of our existing senior secured second lien notes was accounted for as a modification of those notes. Therefore, no gain or loss was recognized, and previously deferred debt issuance costs of $6.9 million were treated as a discount to the principal amount of the new 7¾% Senior Secured Notes, which discount will be amortized as interest expense over the term of these notes.

January 2018 Senior Subordinated Note Exchanges

During January 2018, we closed transactions to exchange a total of $174.3 million aggregate principal amount of our then existing senior subordinated notes for $74.1 million aggregate principal amount of new 2022 Senior Secured Notes and $59.4 million aggregate principal amount of our previously outstanding 2023 Convertible Senior Notes, resulting in a net reduction in our debt principal from these exchanges of $40.8 million. The exchanged notes consisted of $11.6 million aggregate principal amount of our 2021 Senior Subordinated Notes, $94.2 million aggregate principal amount of our 2022 Senior Subordinated Notes and $68.5 million aggregate principal amount of our 2023 Senior Subordinated Notes. In May 2018, the debt principal balance and future interest applicable to the 2023 Convertible Senior Notes were reclassified to "Paid-in capital in excess of par" and "Common stock" in our Consolidated Balance Sheets following the conversion of the notes into shares of Denbury common stock (see *Conversions of 2023 and 2024 Convertible Senior Notes into Common Stock in April and May 2018* below for further discussion).

2017 Senior Subordinated Note Exchanges

During December 2017, we entered into privately negotiated agreements to exchange a total of $609.8 million aggregate principal amount of our existing senior subordinated notes for $381.6 million aggregate principal amount of new 2022 Senior Secured Notes and $84.7 million aggregate principal amount of 3½% Convertible Senior Notes due 2024, resulting in a net reduction in our debt principal from these exchanges of $143.6 million. The exchanged notes consisted of $364.0 million aggregate principal amount of our 2022 Senior Subordinated Notes and $245.8 million aggregate principal amount of our 2023 Senior Subordinated Notes.

Conversions of 2023 and 2024 Convertible Senior Notes into Common Stock in April and May 2018

During the second quarter of 2018, holders of all $59.4 million aggregate principal amount outstanding of our 2023 Convertible Senior Notes and $84.7 million aggregate principal amount outstanding of our 3½% Convertible Senior Notes due 2024 converted their notes into shares of Denbury common stock, at the rates specified in the indentures for these notes, resulting in the issuance of 55.2 million shares of our common stock upon conversion. The debt principal balances and future interest treated as debt applicable to the 2023 Convertible Senior Notes and 3½% Convertible Senior Notes due 2024, totaling $162.0 million, were reclassified to "Paid-in capital in excess of par" and "Common stock" in our Consolidated Balance Sheets upon the conversion of the notes into shares of Denbury common stock. As of April 18, 2018 and May 30, 2018, there were no remaining 3½% Convertible Senior Notes due 2024 and 2023 Convertible Senior Notes outstanding, respectively.

Senior Secured Second Lien Notes

9% Senior Secured Second Lien Notes due 2021. In May 2016, we issued $614.9 million of 2021 Senior Secured Notes. The 2021 Senior Secured Notes, which bear interest at a rate of 9% per annum, were issued at par in connection with privately negotiated exchanges with a limited number of holders of existing senior subordinated notes. The 2021 Senior Secured Notes mature on May 15, 2021, and interest is payable semiannually in arrears on May 15 and November 15 of each year. At any time prior to December 15, 2020, we may redeem the 2021 Senior Secured Notes in whole or in part at our option, at a redemption price of 104.50% of the principal amount, and at par thereafter, as specified in the indenture. The 2021 Senior Secured Notes are not subject to any sinking fund requirements.

The 2021 Senior Secured Notes are guaranteed jointly and severally by our subsidiaries representing substantially all of our assets, operations and income and are secured by second-priority liens on substantially all of the assets that secure the Bank Credit Agreement, which second-priority liens are contractually subordinated to liens that secure our Bank Credit Agreement and any future additional priority lien debt.

9¼% Senior Secured Second Lien Notes due 2022. In December 2017 and January 2018, we issued $381.6 million and $74.1 million, respectively, of 2022 Senior Secured Notes. The 2022 Senior Secured Notes, which bear interest at a rate of 9.25% per annum, were issued at par in connection with exchanges with a limited number of holders of existing senior subordinated notes (see *January 2018 Senior Subordinated Note Exchanges* and *2017 Senior Subordinated Note Exchanges* above). The 2022 Senior Secured Notes mature on March 31, 2022, and interest is payable semiannually in arrears on March 31 and September 30 of each year. We may redeem the 2022 Senior Secured Notes in whole or in part at our option, at a redemption price of 109.25% of the principal amount at any time prior to March 31, 2020, 104.625% of the principal amount prior to March 31, 2021, and at par thereafter. The 2022 Senior Secured Notes are not subject to any sinking fund requirements.

The 2022 Senior Secured Notes are guaranteed jointly and severally by our subsidiaries representing substantially all of our assets, operations and income and are secured by second-priority liens on substantially all of the assets that secure the Bank Credit Agreement, which second-priority liens are contractually subordinated to liens that secure our Bank Credit Agreement and any future additional priority lien debt.

7¾% Senior Secured Second Lien Notes due 2024. In June 2019, we issued $528.0 million of 7¾% Senior Secured Notes in connection with exchanges with certain holders of the Company's outstanding senior subordinated notes and existing 7½% Senior Secured Notes (see *2019 Debt Reduction Transactions* above). The 7¾% Senior Secured Notes, which carry a stated interest rate of 7.75% per annum, were recorded at approximately 94% of their principal amount in accordance with FASC 470-50, *Modifications and Extinguishments*, which equates to an effective yield to maturity of approximately 9.39%. In July 2019, we issued an additional $3.8 million of 7¾% Senior Secured Notes in exchange for $4.0 million of 7½% Senior Secured Notes, which were recorded at par. The 7¾% Senior Secured Notes mature on February 15, 2024, and interest is payable semiannually in arrears on February 15 and August 15 of each year. We may redeem the 7¾% Senior Secured Notes in whole or in part at our option beginning August 15, 2020, at a redemption price of 103.875% of the principal amount, and at declining redemption prices thereafter, as specified in the indenture governing the 7¾% Senior Secured Notes. Prior to August 15, 2020, we may at our option redeem up to an aggregate of 35% of the principal amount of the 7¾% Senior Secured Notes at a price of 107.75% of par with the proceeds of certain equity offerings. In addition, at any time prior to August 15, 2020, we may redeem the 7¾% Senior Secured Notes in whole or in part at a price equal to 100% of the principal amount plus a "make-whole" premium and accrued and unpaid interest. The 7¾% Senior Secured Notes are not subject to any sinking fund requirements.

The 7¾% Senior Secured Notes are guaranteed jointly and severally by our subsidiaries representing substantially all of our assets, operations and income and are secured by second-priority liens on substantially all of the assets that secure the Bank Credit Agreement, which second-priority liens are contractually subordinated to liens that secure our Bank Credit Agreement and any future additional priority lien debt.

7½% Senior Secured Second Lien Notes due 2024. In August 2018, we issued $450.0 million of 7½% Senior Secured Notes. The 7½% Senior Secured Notes, which bear interest at a rate of 7.50% per annum, were issued at par to repay outstanding borrowings on our Bank Credit Agreement, with additional proceeds used for general corporate purposes. After note exchanges completed in June and July of 2019, $20.6 million principal amount of the 7½% Senior Secured Notes remained outstanding as of December 31, 2019. The 7½% Senior Secured Notes mature on February 15, 2024, and interest is payable semiannually in arrears on February 15 and August 15 of each year. We may redeem the 7½% Senior Secured Notes in whole or in part at our option beginning August 15, 2020, at a redemption price of 103.75% of the principal amount, and at declining redemption prices thereafter, as specified in the indenture governing the 7½% Senior Secured Notes. Prior to August 15, 2020, we may at our option redeem up to an aggregate of 35% of the principal amount of the 7½% Senior Secured Notes at a price of 107.50% of par with the proceeds of certain equity offerings. In addition, at any time prior to August 15, 2020, we may redeem the 7½% Senior Secured Notes in whole or in part at a price equal to 100% of the principal amount plus a "make-whole" premium and accrued and unpaid interest. The 7½% Senior Secured Notes are not subject to any sinking fund requirements.

The 7½% Senior Secured Notes are guaranteed jointly and severally by our subsidiaries representing substantially all of our assets, operations and income and are secured by second-priority liens on substantially all of the assets that secure the Bank Credit Agreement, which second-priority liens are contractually subordinated to liens that secure our Bank Credit Agreement and any future additional priority lien debt.

Restrictive Covenants in Indentures for Senior Secured Second Lien Notes. Each of the indentures for the 2021 Senior Secured Notes, 2022 Senior Secured Notes, 7¾% Senior Secured Notes and 7½% Senior Secured Notes contains customary covenants that are generally consistent and that restrict our ability and the ability of our restricted subsidiaries to (1) incur additional debt; (2) make investments; (3) create liens on our assets or the assets of our restricted subsidiaries; (4) create limitations on the ability of our restricted subsidiaries to pay dividends or make other payments to DRI or other restricted subsidiaries; (5) engage in transactions with our affiliates; (6) transfer or sell assets or subsidiary stock; (7) consolidate, merge or transfer all or substantially all of our assets and the assets of our restricted subsidiaries; and (8) make restricted payments (which includes paying dividends on our common stock or redeeming, repurchasing or retiring such stock or subordinated debt (including existing senior subordinated notes)), provided that in certain circumstances we may make unlimited restricted payments so long as we maintain a Leverage Ratio (as defined in the indentures) not to exceed 2.5 to 1.0 (both before and after giving effect to any restricted payment). As of December 31, 2019, we were in compliance with all debt covenants under the indentures related to our senior secured second lien notes.

Convertible Senior Notes

6⅜% Convertible Senior Notes due 2024. In June 2019, we issued $245.5 million of 2024 Convertible Senior Notes in connection with exchanges with certain holders of the Company's outstanding senior subordinated notes (see *2019 Debt Reduction Transactions* above). The 2024 Convertible Senior Notes, which carry a stated interest rate of 6.375% per annum, were recorded at approximately 67% of their principal amount in accordance with FASC 470-50, *Modifications and Extinguishments*, which equates to an effective yield to maturity of approximately 15.31%. Interest on the 2024 Convertible Senior Notes is payable semiannually in arrears on June 30 and December 30 of each year and mature on December 31, 2024. We do not have the right to redeem the 2024 Convertible Senior Notes prior to their maturity. The 2024 Convertible Senior Notes are convertible into shares of our common stock at any time, at the option of the holders, at a rate of 370 shares of common stock per $1,000 principal amount of 2024 Convertible Senior Notes, which is equivalent to approximately 90.9 million shares of the Company's common stock, subject to customary adjustments to the conversion rate and threshold price with respect to, among other things, stock dividends and distributions, mergers and reclassifications. The 2024 Convertible Senior Notes will be automatically converted into shares of common stock at this rate if the volume weighted average trading price of the Company's common stock equals or exceeds the threshold price, which is $2.43 per share, for 10 trading days in any period of 15 consecutive trading days, subject to satisfaction of certain other conditions. Additionally, the Company may, based on a determination of its Board of Directors that such changes are in the best interests of the Company, and subject to certain limitations, increase the conversion rate. Any such conversion rate increase would cause a proportional decrease in the threshold price for mandatory conversions, and thereby would enable the Company to require a mandatory conversion into common stock at a lower price.

Restrictive Covenants in Indentures for Convertible Senior Notes. The indenture for the 2024 Convertible Senior Notes contains certain covenants that restrict our ability and the ability of our restricted subsidiaries to take or permit certain actions, including restrictions on our ability and the ability of our restricted subsidiaries to (1) incur additional debt; (2) make investments; (3) create liens on our assets or the assets of our restricted subsidiaries; (4) create restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to DRI or other restricted subsidiaries; (5) engage in transactions with our affiliates; (6) transfer or sell assets or subsidiary stock; (7) consolidate, merge or transfer all or substantially all of our assets and the assets of our restricted subsidiaries; and (8) make restricted payments (which includes paying dividends on our common stock or redeeming, repurchasing or retiring such stock or subordinated debt), provided that in certain circumstances we may make unlimited restricted payments so long as we maintain a Leverage Ratio (both as defined in the indenture) not to exceed 2.5 to 1.0

(both before and after giving effect to any restricted payment). As of December 31, 2019, we were in compliance with all debt covenants under the indenture related to our convertible senior notes.

Senior Subordinated Notes

6⅜% Senior Subordinated Notes due 2021. In February 2011, we issued $400 million of 2021 Senior Subordinated Notes. The 2021 Senior Subordinated Notes, which bear interest at a rate of 6.375% per annum, were sold at par. After note repurchases in open market transactions and exchange transactions completed over the last four years, $51.3 million principal amount of the 2021 Senior Subordinated Notes remained outstanding as of December 31, 2019. The 2021 Senior Subordinated Notes mature on August 15, 2021, and interest is payable on February 15 and August 15 of each year. We may redeem the 2021 Senior Subordinated Notes in whole or in part at our option at a redemption price of 100% of the principal amount.

5½% Senior Subordinated Notes due 2022. In April 2014, we issued $1.25 billion of 2022 Senior Subordinated Notes. The 2022 Senior Subordinated Notes, which bear interest at a rate of 5.5% per annum, were sold at par. After note repurchases in open market transactions and exchange transactions completed over the last four years, $58.4 million principal amount of the 2022 Senior Subordinated Notes remained outstanding as of December 31, 2019. The 2022 Senior Subordinated Notes mature on May 1, 2022, and interest is payable on May 1 and November 1 of each year. At any time prior to May 1, 2020, we may redeem the 2022 Senior Subordinated Notes in whole or in part at our option, at a redemption price of 101.375% of the principal amount, and at par thereafter, as specified in the indenture. The 2022 Senior Subordinated Notes are not subject to any sinking fund requirements.

4⅝% Senior Subordinated Notes due 2023. In February 2013, we issued $1.2 billion of 2023 Senior Subordinated Notes. The 2023 Senior Subordinated Notes, which bear interest at a rate of 4.625% per annum, were sold at par. After note repurchases in open market transactions and exchange transactions completed over the last four years, $136.0 million principal amount of the 2023 Senior Subordinated Notes remained outstanding as of December 31, 2019. The 2023 Senior Subordinated Notes mature on July 15, 2023, and interest is payable on January 15 and July 15 of each year. At any time prior to January 15, 2021, we may redeem the 2023 Senior Subordinated Notes in whole or in part at our option at a redemption price of 100.771% of the principal amount, and at par thereafter, as specified in the indenture. The 2023 Senior Subordinated Notes are not subject to any sinking fund requirements.

Restrictive Covenants in Indentures for Senior Subordinated Notes. Each of the indentures for the 2021 Senior Subordinated Notes, 2022 Senior Subordinated Notes and 2023 Senior Subordinated Notes contains certain covenants that are generally consistent and that restrict our ability and the ability of our restricted subsidiaries to take or permit certain actions, including restrictions on our ability and the ability of our restricted subsidiaries to (1) incur additional debt; (2) make investments; (3) create liens on our assets or the assets of our restricted subsidiaries; (4) create restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to DRI or other restricted subsidiaries; (5) engage in transactions with our affiliates; (6) transfer or sell assets or subsidiary stock; (7) consolidate, merge or transfer all or substantially all of our assets and the assets of our restricted subsidiaries; and (8) make restricted payments (which includes paying dividends on our common stock or redeeming, repurchasing or retiring such stock or subordinated debt), provided that the restricted payments covenant in the indentures for the 2022 Senior Subordinated Notes and 2023 Senior Subordinated Notes permits us in certain circumstances to make unlimited restricted payments so long as we maintain a Leverage Ratio (both as defined in the 2022 Senior Subordinated Notes and 2023 Senior Subordinated Notes Indentures) not to exceed 2.5 to 1.0 (both before and after giving effect to any restricted payment), although we will not be able to realize the practical benefit of the restricted payment covenant flexibility in the 2022 Senior Subordinated Notes and 2023 Senior Subordinated Notes Indentures until the 2021 Senior Subordinated Notes have been redeemed or retired. As of December 31, 2019, we were in compliance with all debt covenants under the indentures related to our senior subordinated notes.

Pipeline Financings

In May 2008, we closed two transactions with Genesis Energy, L.P. (“Genesis”) involving two of our pipelines. The NEJD Pipeline system included a 20-year financing, and the Free State Pipeline included a long-term transportation service agreement. These transactions are both accounted for as financing arrangements under FASC Topic 840, *Leases*.

Debt Issuance Costs

In connection with the issuance of our outstanding long-term debt, we have incurred debt issuance costs, which are being amortized to interest expense using the straight line or effective interest method over the term of each related facility or borrowing. Remaining unamortized debt issuance costs were $14.0 million and $19.1 million at December 31, 2019 and 2018, respectively. Issuance costs associated with our Bank Credit Agreement are included in "Other assets" in our Consolidated Balance Sheets, and issuance costs associated with our senior secured second lien notes, convertible senior notes, and senior subordinated notes are included as a reduction of "Long-term debt, net of current portion" in our Consolidated Balance Sheets.

Indebtedness Repayment Schedule

At December 31, 2019, our indebtedness, including our financing lease obligations but excluding future interest payable treated as debt in accordance with FASC 470-60, *Troubled Debt Restructuring by Debtors*, is payable over the next five years and thereafter as follows (assuming our 2024 Convertible Senior Notes do not convert into shares of our common stock prior to maturity):

In thousands	
2020	$ 15,323
2021	683,562
2022	532,157
2023	155,293
2024	817,297
Thereafter	78,094
Total indebtedness	$ 2,281,726

Note 7. Income Taxes

Our income tax provision (benefit) is as follows:

	Year Ended December 31,		
In thousands	2019	2018	2017
Current income tax expense (benefit)			
Federal	$ 2,645	$ (17,885)	$ (19,485)
State	1,236	1,884	(1,388)
Total current income tax expense (benefit)	3,881	(16,001)	(20,873)
Deferred income tax expense (benefit)			
Federal	89,950	93,395	(113,863)
State	10,521	9,839	18,084
Total deferred income tax expense (benefit)	100,471	103,234	(95,779)
Total income tax expense (benefit)	$ 104,352	$ 87,233	$ (116,652)

At December 31, 2019, we had no federal net operating loss carryforwards ("NOLs"), tax effected business interest expense carryforward totaling $24.5 million (before provision for valuation allowance), state NOLs and tax credits totaling $52.9 million (before provision for valuation allowance), an estimated $49.9 million of enhanced oil recovery credits to carry forward related to our tertiary operations, an estimated $21.6 million of research and development credits, and $6.0 million of alternative minimum tax credits. Under the Tax Cut and Jobs Act ("the Act") enacted in December 2017, all of our alternative minimum tax credits are fully refundable by 2021 and are recorded as a receivable on the balance sheet. We considered our assessment of the recorded tax benefit associated with the impacts of the Act to be substantially complete as of December 31, 2018, which is reflected in the table reconciling income tax expense below. Federal and state regulatory guidance of the Act are continuing to be issued and could result in further tax effects but are not expected to be material to our financial statements. In addition, the Tax Cut and Jobs Act revised the rules regarding the deductibility of business interest expense by limiting that deduction to 30% of adjusted taxable income (as defined), with disallowed amounts being carried forward to future taxable years. Based on our evaluation, using information existing as of the balance sheet date, of the near-term ability to utilize the tax benefits associated with our 2019 and 2018 disallowed business interest expense, we have established a valuation allowance of $24.5 million for that portion of our business interest expense that is currently expected to exceed the allowed limitation under the Act. Our business interest expense carryforward does not expire. Our state NOLs expire in various years, starting in 2020, although most do not begin to expire until 2025. Our enhanced oil recovery credits and research and development credits begin to expire in 2025 and 2031, respectively.

Deferred income taxes reflect the available tax carryforwards and the temporary differences based on tax laws and statutory rates in effect at the December 31, 2019 and 2018 balance sheet dates. As of December 31, 2019, we had $52.7 million of deferred tax assets associated with State of Louisiana, Mississippi and Alabama net operating losses and tax credits. A tax valuation allowance was recorded in 2015 to reduce the carrying value of our Louisiana deferred tax assets as the result of a tax law enacted in the State of Louisiana, which limits a company's utilization of certain deductions, including our net operating loss carryforwards. As of December 31, 2019, tax valuation allowances totaling $41.3 million were recorded for our State of Louisiana deferred tax assets. Based on losses from falling commodity prices and lower future forecasted income related to our Mississippi deferred tax assets, we concluded it was not more likely than not that the deferred tax assets would be realized. Accordingly, we recorded a valuation allowance against our Mississippi deferred tax assets in 2017. As of December 31, 2019, tax valuation allowances totaling $10.6 million were recorded for our State of Mississippi deferred tax assets. During 2019, we recorded a valuation allowance against our Alabama deferred tax assets totaling $0.8 million. After closing on the sale of our Citronelle Field in 2019, our ability to utilize our Alabama net operating losses will be limited, and we concluded it was not more likely than not that the deferred tax assets would be realized. The valuation allowances will remain until the realization of future deferred tax benefits are more likely than not to become utilized. The changes in our valuation allowance established for our state net operating losses and business interest expense carryforward for 2019, 2018, and 2017 are detailed below:

	Year Ended December 31,		
In thousands	2019	2018	2017
Balance at beginning of year	$ 51,093	$ 51,134	$ 36,510
Federal	23,124	—	—
State	2,998	(41)	14,624
Balance at end of year	$ 77,215	$ 51,093	$ 51,134

As of December 31, 2019, we had an unrecognized tax benefit of $5.4 million related to an uncertain tax position. The unrecognized tax benefit was recorded during 2015 as a direct reduction of the associated deferred tax asset and, if recognized, would not materially affect our annual effective tax rate. The tax benefit from an uncertain tax position will only be recognized if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. We currently do not expect a material change to the uncertain tax position within the next 12 months. Our policy is to recognize penalties and interest related to uncertain tax positions in income tax expense; however, no such amounts were accrued related to the uncertain tax position as of December 31, 2019.

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Significant components of our deferred tax assets and liabilities as of December 31, 2019 and 2018 are as follows:

	December 31,	
In thousands	2019	2018
Deferred tax assets		
Loss and tax credit carryforwards – state	$ 52,917	$ 52,366
Business interest expense carryforward	24,513	9,049
Business credit carryforwards	71,555	79,528
Unrecognized gain and original issue discount on debt exchange	41,556	73,937
Accrued liabilities and other reserves	29,788	25,231
Other	18,725	23,208
Valuation allowances	(77,215)	(51,093)
Total deferred tax assets	161,839	212,226
Deferred tax liabilities		
Property and equipment	(569,254)	(492,214)
Derivative contracts	(1,120)	(23,127)
Other	(1,695)	(6,643)
Total deferred tax liabilities	(572,069)	(521,984)
Total net deferred tax liability	$ (410,230)	$ (309,758)

Our reconciliation of income tax expense computed by applying the U.S. federal statutory rate and the reported effective tax rate on income from continuing operations is as follows:

	Year Ended December 31,		
In thousands	2019	2018	2017
Income tax provision calculated using the federal statutory income tax rate	$ 67,475	$ 86,086	$ 16,275
State income taxes, net of federal income tax benefit	7,435	11,968	2,764
Tax shortfall (windfall) on stock-based compensation deduction	1,912	(1,565)	5,567
Valuation allowance	26,122	(42)	5,562
Enhanced oil recovery tax credits generated	—	(10,818)	(11,307)
Re-measurement of deferreds related to federal tax rate change	—	—	(132,224)
Other	1,408	1,604	(3,289)
Total income tax expense (benefit)	$ 104,352	$ 87,233	$ (116,652)

We file consolidated and separate income tax returns in the U.S. federal jurisdiction and in many state jurisdictions. The statutes of limitation for our income tax returns for tax years ending prior to 2016 have lapsed and therefore are not subject to examination by respective taxing authorities. We have not paid any significant interest or penalties associated with our income taxes.

Note 8. Stockholders' Equity

401(k) Plan

We offer a 401(k) plan to which employees may contribute earnings subject to IRS limitations. We match 100% of an employee's contribution, up to 6% of compensation, as defined by the plan, which is vested immediately. During 2019, 2018 and 2017, our matching contributions to the 401(k) plan were approximately $6.3 million, $6.2 million and $7.1 million, respectively.

Note 9. Stock Compensation

The Amended and Restated 2004 Omnibus Stock and Incentive Plan, amended and restated as of March 28, 2019 (the “2004 Plan”), is an incentive plan that provides for the issuance of incentive and non-qualified stock options, restricted stock awards, restricted stock units, stock appreciation rights (“SARs”) settled in stock, and performance-based awards to officers, employees and directors. Since the 2004 Plan’s inception, awards covering a total of 61.4 million shares of common stock have been authorized for issuance pursuant to the 2004 Plan. As of December 31, 2019, 13.6 million shares were available under the 2004 Plan for future issuance of awards, all of which could be issued in the form of restricted stock or performance-based awards. Our incentive compensation program is administered by the Compensation Committee of our Board of Directors. The 2004 Plan was last approved by our stockholders in May 2019 and will expire in May 2029.

Stock-based compensation expense is included in “General and administrative expenses” in the Consolidated Statements of Operations. Stock-based compensation associated with our employees involved in exploration and drilling activities is capitalized as part of “Oil and natural gas properties” in the Consolidated Balance Sheets. Our accounting policy is to account for forfeitures as they occur.

Stock-based compensation costs for the years ended December 31, 2019, 2018 and 2017, are as follows:

	Year Ended December 31,		
In thousands	2019	2018	2017
Stock-based compensation expense included in G&A	$ 12,470	$ 11,951	$ 15,154
Stock-based compensation capitalized	4,018	3,487	4,567
Total cost of stock-based compensation arrangements	$ 16,488	$ 15,438	$ 19,721
Income tax benefit recognized for stock-based compensation arrangements	$ 3,118	$ 2,988	$ 5,759

SARs

Prior to January 1, 2016, we granted SARs settled in stock to our employees. The SARs generally become exercisable over a three-year vesting period, with the specific terms of vesting determined at the time of grant based on guidelines established by the Compensation Committee of the Board of Directors. The SARs expire over terms not to exceed 7 years from the date of grant, 90 days after termination of employment, 90 days or one year after permanent disability, depending on the award, or one year after the death of the optionee. The SARs were granted with a strike price equal to the fair market value at the time of grant, which is generally defined as the closing price on the NYSE on the date of grant.

The following is a summary of our SAR activity:

	Number of Awards	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2018	2,500,885	$ 10.41		
Granted	—	—		
Exercised	—	—		
Forfeited	—	—		
Expired	(519,729)	15.29		
Outstanding at December 31, 2019	1,981,156	9.12	1.5	$ —
Exercisable at end of period	1,981,156	$ 9.12	1.5	$ —

The following is a summary of the total intrinsic value of SARs exercised and grant-date fair value of SARs vested:

	Year Ended December 31,		
In thousands	2019	2018	2017
Intrinsic value of SARs exercised	$ —	$ —	$ —
Grant-date fair value of SARs vested	—	1,095	1,818

As of December 31, 2018, all SARs vested and there was no remaining compensation cost to be recognized in future periods related to nonvested share-based SAR compensation arrangements. There were no exercises of SARs for the years ended December 31, 2019, 2018 or 2017.

Restricted Stock

We grant non-performance-based restricted stock to employees and directors as part of our long-term compensation program. Holders of non-performance-based restricted stock awards have the rights of owning non-restricted stock (including voting rights) except that the holders are not entitled to delivery of a portion thereof until certain requirements are met. Beginning in 2014, non-performance-based restricted stock awards provide the holders with forfeitable dividend equivalent rights which vests with the underlying shares. Non-performance-based restricted stock vests over a three-year vesting period, with the specific terms of vesting determined at the time of grant.

As of December 31, 2019, there was $17.4 million of unrecognized compensation expense related to nonvested non-performance-based restricted stock grants. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 2.0 years. The following is a summary of the total vesting date fair value of non-performance-based restricted stock:

	Year Ended December 31,		
In thousands	2019	2018	2017
Fair value of restricted stock vested	$ 5,743	$ 23,060	$ 9,325

A summary of the status of our nonvested non-performance-based restricted stock grants issued, and the changes during the year ended December 31, 2019, is presented below:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2018	8,990,578	$ 3.40
Granted	9,630,155	1.15
Vested	(4,612,265)	3.20
Forfeited	(1,601,032)	2.05
Nonvested at December 31, 2019	12,407,436	1.91

Performance-Based Equity Awards

Annually, the Compensation Committee of the Board of Directors grants performance-based equity awards to Denbury's officers. Performance-based awards generally vest over 1.25 to 3.25 years for awards granted in 2017 and over 3.25 years for awards granted in 2018 and 2019. The number of performance-based shares earned (and eligible to vest) during the performance period will depend upon: (1) our level of success in achieving specifically identified performance targets ("Performance-Based Operational Awards") and (2) performance of our stock relative to that of a designated peer group ("Performance-Based TSR Awards"). Generally, one-half of the maximum number of shares that could be earned under the performance-based awards will be earned for performance at the designated target levels (100% target vesting levels) or upon any earlier change of control, and twice the target number of shares will be earned if the maximum target levels are met (200% of target vesting levels). With respect to the performance-based equity awards, any amounts earned above the 100% target levels will be payable in cash, rather than in shares of Denbury stock, in order to conserve available shares under the Plan. If performance is below the designated minimum levels, no performance-based shares will be earned. Performance-Based Operational Awards are valued using the fair market value of Denbury stock, and Performance-Based TSR Awards are valued using a Monte Carlo simulation.

As of December 31, 2019, there was $5.7 million of unrecognized compensation expense related to nonvested performance-based equity awards. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 1.9 years. The range of assumptions used in the Monte Carlo simulation valuation approach for Performance-Based TSR Awards (presented at the target level) are as follows:

	Year Ended December 31,		
	2019	2018	2017
Weighted average fair value of Performance-Based TSR Awards granted	$ 1.95	$ 2.29	$ 3.42
Risk-free interest rate	2.27%	2.37%	1.49%
Expected life	3.0 years	3.0 years	3.0 years
Expected volatility	77.2%	102.9%	94.7%
Dividend yield	—%	—%	—%

A summary of the status of the nonvested performance-based equity awards (presented at the target level) during the year ended December 31, 2019, is as follows:

	Performance-Based Operational Awards		Performance-Based TSR Awards	
	Number of Awards	Weighted Average Grant-Date Fair Value	Number of Awards	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2018	857,812	$ 2.43	3,806,116	$ 2.71
Granted(1)	980,772	2.13	2,027,660	1.95
Vested(2)	—	—	(1,357,778)	1.78
Forfeited	—	—	—	—
Nonvested at December 31, 2019	1,838,584	2.27	4,475,998	2.65

(1) Amounts granted reflect the number of performance units granted. The actual payout of the shares may be between 0% and 200%, with any amounts earned above the 100% target levels payable in cash, rather than in shares of Denbury stock, in order to conserve available shares under the Plan.
(2) During 2019, the service period lapsed on these TSR performance unit awards. The lapsed units earned a weighted average of 100% of target for each vested TSR performance-based award, representing 1,357,778 aggregate shares of common stock issued. There were no vestings related to Operational performance-based awards during 2019.

The following is a summary of the total vesting date fair value of performance-based equity awards:

	Year Ended December 31,		
In thousands	2019	2018	2017
Vesting date fair value of Performance-Based Operational Awards	$ —	$ 595	$ 1,079
Vesting date fair value of Performance-Based TSR Awards	2,783	542	227

Note 10. Commodity Derivative Contracts

We do not apply hedge accounting treatment to our oil and natural gas derivative contracts; therefore, the changes in the fair values of these instruments are recognized in income in the period of change. These fair value changes, along with the settlements of expired contracts, are shown under “Commodity derivatives expense (income)” in our Consolidated Statements of Operations.

Historically, we have entered into various oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production and to provide more certainty to our future cash flows. We do not hold or issue derivative financial instruments for trading purposes. Generally, these contracts have consisted of various combinations of price floors, collars, three-way collars, fixed-price swaps, fixed-price swaps enhanced with a sold put, and basis swaps. The production that we hedge has varied from year to year depending on our levels of debt, financial strength and expectation of future commodity prices.

We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification, and all of our commodity derivative contracts are with parties that are lenders under our Bank Credit Agreement (or affiliates of such lenders). As of December 31, 2019, all of our outstanding derivative contracts were subject to enforceable master netting arrangements whereby payables on those contracts can be offset against receivables from separate derivative contracts with the same counterparty. It is our policy to classify derivative assets and liabilities on a gross basis on our balance sheets, even if the contracts are subject to enforceable master netting arrangements.

The following table summarizes our commodity derivative contracts as of December 31, 2019, none of which are classified as hedging instruments in accordance with the FASC *Derivatives and Hedging* topic:

			Contract Prices ($/Bbl)					
					Weighted Average Price			
Months	Index Price	Volume (Barrels per day)	Range[1]		Swap	Sold Put	Floor	Ceiling
Oil Contracts:								
2020 Fixed-Price Swaps								
Jan – Dec	NYMEX	2,000	$ 60.00 –	61.00	$ 60.59	$ —	$ —	$ —
Jan – Dec	Argus LLS	4,500	60.72 –	64.26	62.29	—	—	—
2020 Three-Way Collars[2]								
Jan – June	NYMEX	23,000	$ 55.00 –	82.65	$ —	$ 48.25	$ 56.95	$ 62.83
Jan – June	Argus LLS	10,000	58.00 –	87.10	—	52.85	61.52	68.21
July – Dec	NYMEX	21,000	55.00 –	82.65	—	48.26	56.85	62.68
July – Dec	Argus LLS	8,000	58.00 –	87.10	—	52.75	61.08	68.39

(1) Ranges presented for fixed-price swaps represent the lowest and highest fixed prices of all open contracts for the period presented. For three-way collars, ranges represent the lowest floor price and highest ceiling price for all open contracts for the period presented.

(2) A three-way collar is a costless collar contract combined with a sold put feature (at a lower price) with the same counterparty. The value received for the sold put is used to enhance the contracted floor and ceiling price of the related collar. At the contract settlement date, (1) if the index price is higher than the ceiling price, we pay the counterparty the difference between the index price and ceiling price for the contracted volumes, (2) if the index price is between the floor and ceiling price, no settlements occur, (3) if the index price is lower than the floor price but at or above the sold put price, the counterparty pays us the difference between the index price and the floor price for the contracted volumes and (4) if the index price is lower than the sold put price, the counterparty pays us the difference between the floor price and the sold put price for the contracted volumes.

Note 11. Fair Value Measurements

The FASC *Fair Value Measurement* topic defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (often referred to as the "exit price"). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the income approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The FASC establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

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- Level 1 – Quoted prices in active markets for identical assets or liabilities as of the reporting date.
- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. Instruments in this category include non-exchange-traded oil derivatives that are based on NYMEX pricing and fixed-price swaps that are based on regional pricing other than NYMEX (e.g., Light Louisiana Sweet). Our costless collars and the sold put features of our three-way collars are valued using the Black-Scholes model, an industry standard option valuation model that takes into account inputs such as contractual prices for the underlying instruments, maturity, quoted forward prices for commodities, interest rates, volatility factors and credit worthiness, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.
- Level 3 – Pricing inputs include significant inputs that are generally less observable. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. As of December 31, 2019, instruments in this category included non-exchange-traded three-way collars that were based on regional pricing other than NYMEX (e.g., Light Louisiana Sweet). The valuation models utilized for costless collars and three-way collars were consistent with the methodologies described above; however, the implied volatilities utilized in the valuation of Level 3 instruments were developed using a benchmark, which was considered a significant unobservable input. An increase or decrease of 100 basis points in the implied volatility inputs utilized in our fair value measurement would result in a change of approximately $300 thousand in the fair value of these instruments as of December 31, 2019.

We adjust the valuations from the valuation model for nonperformance risk, using our estimate of the counterparty's credit quality for asset positions and our credit quality for liability positions. We use multiple sources of third-party credit data in determining counterparty nonperformance risk, including credit default swaps.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2019 and 2018:

	Fair Value Measurements Using:			
In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2019				
Assets				
Oil derivative contracts – current	$ —	$ 8,503	$ 3,433	$ 11,936
Total Assets	$ —	$ 8,503	$ 3,433	$ 11,936
Liabilities				
Oil derivative contracts – current	$ —	$ (6,522)	$ (1,824)	$ (8,346)
Total Liabilities	$ —	$ (6,522)	$ (1,824)	$ (8,346)
December 31, 2018				
Assets				
Oil derivative contracts – current	$ —	$ 81,621	$ 11,459	$ 93,080
Oil derivative contracts – long-term	—	2,030	2,165	4,195
Total Assets	$ —	$ 83,651	$ 13,624	$ 97,275

Since we do not apply hedge accounting for our commodity derivative contracts, any gains and losses on our assets and liabilities are included in "Commodity derivatives expense (income)" in the accompanying Consolidated Statements of Operations.

Level 3 Fair Value Measurements

The following table summarizes the changes in the fair value of our Level 3 assets and liabilities for the years ended December 31, 2019 and 2018:

	Year Ended December 31,	
In thousands	2019	2018
Fair value of Level 3 instruments, beginning of year	$ 13,624	$ —
Fair value adjustments on commodity derivatives	(8,205)	13,624
Receipt on settlements of commodity derivatives	(3,810)	—
Fair value of Level 3 instruments, end of year	$ 1,609	$ 13,624
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets or liabilities still held at the reporting date	$ (556)	$ 13,624

We utilize an income approach to value our Level 3 three-way collars. We obtain and ensure the appropriateness of the significant inputs to the calculation, including contractual prices for the underlying instruments, maturity, forward prices for commodities, interest rates, volatility factors and credit worthiness, and the fair value estimate is prepared and reviewed on a quarterly basis. The following table details fair value inputs related to implied volatilities utilized in the valuation of our Level 3 oil derivative contracts:

	Fair Value at 12/31/2019 (in thousands)	Valuation Technique	Unobservable Input	Volatility Range
Oil derivative contracts	$ 1,609	Discounted cash flow / Black-Scholes	Volatility of Light Louisiana Sweet for settlement periods beginning after December 31, 2019	12.6% – 34.5%

Other Fair Value Measurements

The carrying value of our loans under our Bank Credit Agreement approximate fair value, as they are subject to short-term floating interest rates that approximate the rates available to us for those periods. We use a market approach to determine the fair value of our fixed-rate long-term debt using observable market data. The fair values of our senior secured second lien notes, convertible senior notes, and senior subordinated notes are based on quoted market prices, which are considered Level 1 measurements under the fair value hierarchy. The estimated fair value of the principal amount of our debt as of December 31, 2019 and 2018, excluding pipeline financing and capital lease obligations, was $1,833.1 million and $1,886.1 million, respectively. We have other financial instruments consisting primarily of cash, cash equivalents, U.S. Treasury notes, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 12. Commitments and Contingencies

Commitments

We have entered into long-term commitments to purchase CO_2 that are either non-cancelable or cancelable only upon the occurrence of specified future events. The commitments continue for up to 9 years. The price we will pay for CO_2 generally varies depending on the amount of CO_2 delivered and the price of oil. Once all commitments have commenced, our annual commitment under these contracts could range from $14 million to $33 million per year, assuming a $60 per Bbl NYMEX oil price.

We are party to long-term contracts that require us to deliver CO_2 to our industrial CO_2 customers at various contracted prices. Based upon the maximum amounts deliverable as stated in the industrial contracts, we estimate that we may be obligated to deliver up to 770 Bcf of CO_2 to these customers over the next 15 years. The maximum volume required in any given year is approximately 257 MMcf/d, which we judge to be minor given the size of our Jackson Dome proved CO_2 reserves at December 31, 2019, our current production capabilities and our projected levels of CO_2 usage for our own tertiary flooding program.

Litigation

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position, results of operations or cash flows, litigation is subject to inherent uncertainties. We accrue for losses from litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

Riley Ridge Helium Supply Contract Claim

As part of our 2010 and 2011 acquisitions of the Riley Ridge Unit and associated gas processing facility that was under construction, the Company assumed a 20-year helium supply contract under which we agreed to supply the helium separated from the full well stream by operation of the gas processing facility to a third-party purchaser, APMTG Helium, LLC (“APMTG”). The helium supply contract provides for the delivery of a minimum contracted quantity of helium, with liquidated damages payable if specified quantities of helium are not supplied in accordance with the terms of the contract. The liquidated damages are capped at an aggregate of $46.0 million over the term of the contract.

As the gas processing facility has been shut-in since mid-2014 due to significant technical issues, we have not been able to supply helium under the helium supply contract. In a case filed in November 2014 in the Ninth Judicial District Court of Sublette County, Wyoming, APMTG claimed multiple years of liquidated damages for non-delivery of volumes of helium specified under the helium supply contract. The Company claimed that its contractual obligations were excused by virtue of events that fall within the force majeure provisions in the helium supply contract.

On March 11, 2019, the trial court entered a final judgment that a force majeure condition did exist, but the Company’s performance was excused by the force majeure provisions of the contract for only a 35-day period in 2014, and as a result the Company should pay APMTG liquidated damages and interest thereon for those time periods from contract commencement to the close of evidence (November 29, 2017). The Company’s position continues to be that its contractual obligations have been and continue to be excused by events that fall within the force majeure provisions of the helium supply contract, so the Company has appealed the trial court’s ruling to the Wyoming Supreme Court. Briefing for the appeal by the Company and APMTG is currently expected to be completed in late May or early June, after which oral arguments will be scheduled and heard prior to the Wyoming Supreme Court entering its judgment on the appeal. The timing and outcome of this appeal process is currently unpredictable, but at this time is anticipated to extend over the next nine to twelve months.

Absent reversal of the trial court’s ruling on appeal, the Company anticipates total liquidated damages would equal the $46.0 million aggregate cap under the helium supply contract plus $5.2 million of associated costs (through December 31, 2019), for a total of $51.2 million, which is included in “Other liabilities” in our Consolidated Balance Sheets as of December 31, 2019, and $49.4 million of which was accrued in the fourth quarter of 2018. The Company currently has a $32.8 million letter of credit posted as security in this case as part of the appeal process.

Other Contingencies

We are subject to audits for various taxes (income, sales and use, and severance) in the various states in which we operate, and from time to time receive assessments for potential taxes that we may owe. In the past, settlement of these matters has not had a material adverse financial impact on us, and currently we have no material assessments for potential taxes.

We are subject to various possible contingencies that arise primarily from interpretation of federal and state laws and regulations affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Although we believe that we have complied with the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued. In addition, production rates, marketing and environmental matters are subject to regulation by various federal and state agencies.

Note 13. Additional Balance Sheet Details

Trade and Other Receivables, Net

In thousands	December 31, 2019	December 31, 2018
Trade accounts receivable, net	$ 12,630	$ 11,643
Federal income tax receivable, net	2,987	9,037
Commodity derivative settlement receivables	675	2,390
Other receivables	2,026	3,900
Total	$ 18,318	$ 26,970

Note 14. Supplemental Cash Flow Information

Supplemental Cash Flow Information

In thousands	Year Ended December 31, 2019	2018	2017
Supplemental cash flow information			
Cash paid for interest, expensed	$ 72,842	$ 50,076	$ 98,261
Cash paid for interest, capitalized	36,671	37,079	30,762
Cash paid for interest, treated as a reduction of debt	85,303	79,606	50,349
Cash paid for income taxes	2,361	492	450
Cash received from income tax refunds	9,820	8,280	13,323
Noncash investing and financing activities			
Increase in asset retirement obligations	13,560	4,499	9,565
Increase (decrease) in liabilities for capital expenditures	(17,740)	14,600	3,930
Conversion of convertible senior notes into common stock	—	162,004	—
Retirement of treasury stock	—	—	46,562

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES (UNAUDITED)

Costs Incurred

The following table summarizes costs incurred and capitalized in oil and natural gas property acquisition, exploration and development activities. Property acquisition costs are those costs incurred to purchase, lease or otherwise acquire property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs, and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling development wells, and to provide facilities for extracting, treating, gathering and storing the oil and natural gas, and the cost of improved recovery systems.

We capitalize interest on unevaluated oil and natural gas properties that have ongoing development activities. Included in costs incurred in the table below is capitalized interest of $34.1 million, $36.5 million and $30.8 million during the years ended December 31, 2019, 2018 and 2017, respectively. Costs incurred also include new asset retirement obligations established, as well as changes to asset retirement obligations resulting from revisions in cost estimates or abandonment dates. Asset retirement obligations included in the table below were $15.2 million, $6.8 million and $5.6 million during the years ended December 31, 2019, 2018 and 2017, respectively. See Note 4, *Asset Retirement Obligations*, for additional information.

Costs incurred in oil and natural gas activities were as follows:

	Year Ended December 31,		
In thousands	2019	2018	2017
Property acquisitions			
Proved	$ 1,542	$ 2,030	$ 75,086
Unevaluated	—	—	15,748
Exploration	2,575	1,030	297
Development	259,641	338,203	274,325
Total costs incurred(1)	$ 263,758	$ 341,263	$ 365,456

(1) Capitalized general and administrative costs that directly relate to exploration and development activities were $39.5 million, $37.2 million and $41.1 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Denbury Resources Inc.
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Oil and Natural Gas Operating Results

Results of operations from oil and natural gas producing activities, excluding corporate overhead and interest costs, were as follows:

	Year Ended December 31,		
In thousands, except per-BOE data	2019	2018	2017
Oil, natural gas, and related product sales	$ 1,212,020	$ 1,422,589	$ 1,089,666
Lease operating expenses	477,220	489,720	447,799
Transportation and marketing expenses	41,810	43,942	44,064
Production and ad valorem taxes	86,820	96,589	79,198
Depletion, depreciation, and amortization	161,400	144,423	134,721
CO_2 properties and pipelines depletion and depreciation[(1)]	53,120	48,792	49,241
Commodity derivatives expense (income)	70,078	(21,087)	77,576
Net operating income	321,572	620,210	257,067
Income tax provision	80,393	155,053	97,685
Results of operations from oil and natural gas producing activities	$ 241,179	$ 465,157	$ 159,382
Depletion, depreciation, and amortization per BOE	$ 10.10	$ 8.77	$ 8.36

(1) Represents an allocation of the depletion and depreciation of our CO_2 properties and pipelines associated with our tertiary oil producing activities.

Oil and Natural Gas Reserves

Net proved oil and natural gas reserve estimates for all years presented were prepared by DeGolyer and MacNaughton, independent petroleum engineers located in Dallas, Texas. These oil and natural gas reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. See *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves* below for a discussion of the effect of the different prices on reserve quantities and values. Operating costs, production and ad valorem taxes, and future development costs were based on current costs as of December 31, 2019.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present values should not be construed as the current market value of our oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. Estimates of reserves as of year-end 2019, 2018 and 2017 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the applicable fiscal 12-month period. All of our reserves are located in the United States.

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Estimated Quantities of Proved Reserves

	Year Ended December 31,								
	2019			2018			2017		
	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)
Balance at beginning of year	255,042	43,008	262,210	252,625	42,721	259,745	247,103	44,315	254,489
Revisions of previous estimates	(6,799)	(15,299)	(9,348)	21,658	6,115	22,677	14,352	2,541	14,775
Improved recovery(1)	977	—	977	2,314	(157)	2,288	1,936	—	1,936
Production	(20,685)	(3,375)	(21,248)	(21,364)	(3,962)	(22,024)	(21,320)	(4,135)	(22,009)
Acquisition of minerals in place	—	—	—	—	—	—	10,554	—	10,554
Sales of minerals in place	(2,402)	—	(2,402)	(191)	(1,709)	(476)	—	—	—
Balance at end of year	226,133	24,334	230,189	255,042	43,008	262,210	252,625	42,721	259,745
Proved Developed Reserves – end of year	202,816	24,333	206,872	222,736	42,912	229,888	222,531	42,435	229,603
Proved Undeveloped Reserves – end of year	23,317	1	23,317	32,306	96	32,322	30,094	286	30,142

(1) Improved recovery reflects reserve additions that result from the application of secondary recovery methods such as water flooding or tertiary recovery methods such as CO_2 flooding. In order to recognize proved tertiary oil reserves, we must either have an oil production response to CO_2 injections or the field must be analogous to an existing tertiary flood. The magnitude of proved reserves that we can book in any given year will depend on our progress with new floods and the timing of the production response.

Revisions of previous estimates during 2019, 2018, and 2017 primarily reflect changes in commodity prices between December 31, 2016 and 2019.

There were no significant additions, excluding acquisitions of minerals in place in 2017, to our oil and natural gas reserves, as the magnitude of proved reserves that we can book in any given year depends on our progress with new floods and the timing of the production response, and we initiated no new floods in 2019, 2018 or 2017. Acquisitions of minerals in place during 2017 were primarily related to our non-operated working interest acquisitions in Salt Creek and West Yellow Creek fields.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves

The Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves ("Standardized Measure") does not purport to present the fair market value of our oil and natural gas properties. An estimate of such value should consider, among other factors, anticipated future prices of oil and natural gas, the probability of recoveries in excess of existing proved reserves, the value of probable reserves and acreage prospects, and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revision.

Under the Standardized Measure, future cash inflows were estimated by applying a first-day-of-the-month 12-month average price to the estimated future production of year-end proved reserves. These prices have a significant impact on both the quantities and value of the proved reserves, as reductions in oil and natural gas prices can cause wells to reach the end of their economic life much sooner and can make certain proved undeveloped locations uneconomical, both of which reduce the reserves. The following representative oil and natural gas prices were used in the Standardized Measure. These prices were adjusted by field to arrive at the appropriate corporate net price.

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	December 31, 2019	December 31, 2018	December 31, 2017
Oil (NYMEX price per Bbl)	$ 55.69	$ 65.56	$ 51.34
Natural Gas (Henry Hub price per MMBtu)	2.58	3.10	2.98

The changes in the Standardized Measure of discounted future net cash flows in the tables that follow were significantly impacted by the movement in first-day-of-the-month average NYMEX oil prices between 2017 and 2019. The weighted-average oil prices we receive relative to NYMEX oil prices (our NYMEX oil price differential) utilized were $0.14 per Bbl below representative NYMEX oil prices as of December 31, 2019, compared to $0.24 per Bbl below representative NYMEX oil prices as of December 31, 2018, and $2.25 per Bbl below representative NYMEX oil prices as of December 31, 2017.

Future cash inflows were reduced by estimated future production, development and abandonment costs based on current cost, with no escalation to determine pre-tax cash inflows. Our future net inflows do not include a reduction for cash previously expended on our capitalized CO_2 assets that will be consumed in the production of proved tertiary reserves. Future income taxes were computed by applying the statutory tax rate to the excess of net cash inflows over our tax basis in the associated proved oil and natural gas properties. Tax credits and net operating loss carryforwards were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

In thousands	December 31, 2019	December 31, 2018	December 31, 2017
Future cash inflows	$ 12,494,358	$ 16,657,988	$ 12,421,620
Future production costs	(6,813,610)	(8,000,884)	(6,623,563)
Future development costs	(1,434,934)	(1,524,476)	(1,433,900)
Future income taxes	(586,441)	(1,186,769)	(528,767)
Future net cash flows	3,659,373	5,945,859	3,835,390
10% annual discount for estimated timing of cash flows	(1,398,334)	(2,594,474)	(1,602,961)
Standardized measure of discounted future net cash flows	$ 2,261,039	$ 3,351,385	$ 2,232,429

The following table sets forth an analysis of changes in the Standardized Measure of Discounted Future Net Cash Flows from proved oil and natural gas reserves:

In thousands	Year Ended December 31, 2019	Year Ended December 31, 2018	Year Ended December 31, 2017
Beginning of year	$ 3,351,385	$ 2,232,429	$ 1,399,217
Sales of oil and natural gas produced, net of production costs	(608,060)	(797,132)	(523,049)
Net changes in prices and production costs	(1,244,859)	1,963,333	1,231,649
Improved recovery(1)	5,785	11,536	6,119
Previously estimated development costs incurred	81,024	109,214	89,238
Change in future development costs	(35,624)	(42,240)	39,926
Revisions due to timing and other	41,841	10,915	(71,141)
Accretion of discount	367,313	234,434	142,007
Acquisition of minerals in place	—	—	77,366
Sales of minerals in place	(16,892)	1,281	—
Net change in income taxes	319,126	(372,385)	(158,903)
End of year	$ 2,261,039	$ 3,351,385	$ 2,232,429

(1) Improved recovery additions result from the application of secondary recovery methods such as water flooding or tertiary recovery methods such as CO_2 flooding.

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SUPPLEMENTAL CO_2 DISCLOSURES (UNAUDITED)

Based on engineering reports prepared by DeGolyer and MacNaughton, proved CO_2 reserves were estimated as follows:

	Year Ended December 31,		
In MMcf	2019	2018	2017
CO_2 reserves			
Gulf Coast region[1]	4,786,881	4,982,440	5,164,741
Rocky Mountain region[2]	1,120,060	1,155,538	1,187,787

(1) Proved CO_2 reserves in the Gulf Coast region consist of reserves from our reservoirs at Jackson Dome and are presented on a gross (8/8ths) basis, of which our net revenue interest was approximately 3.8 Tcf, 4.0 Tcf and 4.1 Tcf at December 31, 2019, 2018 and 2017, respectively, and include reserves dedicated to volumetric production payments of 3.1 Bcf and 7.6 Bcf at December 31, 2018 and 2017, respectively.

(2) Proved CO_2 reserves in the Rocky Mountain region consist of our overriding royalty interest in LaBarge Field, of which our net revenue interest was approximately 1.1 Tcf, 1.2 Tcf and 1.2 Tcf at December 31, 2019, 2018 and 2017, respectively.

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UNAUDITED QUARTERLY INFORMATION

In thousands, except per-share data	March 31	June 30	September 30	December 31
2019				
Revenues and other income	$ 305,452	$ 343,365	$ 315,453	$ 310,613
Commodity derivatives expense (income)	83,377	(24,760)	(43,155)	54,616
Other expenses	258,508	156,056	248,696	220,234
Net income (loss)	(25,674)	146,692	72,862	23,079
Net income (loss) per common share:				
Basic	(0.06)	0.32	0.16	0.05
Diluted	(0.06)	0.32	0.14	0.05
Cash flow provided by operating activities	64,366	148,634	130,578	150,565
Cash flow used in investing activities	(91,801)	(67,338)	(55,439)	(55,114)
Cash flow used in financing activities	(5,207)	(81,064)	(64,631)	(95,453)
2018				
Revenues and other income	$ 353,234	$ 387,063	$ 394,973	$ 338,355
Commodity derivatives expense (income)	48,825	96,199	44,577	(210,688)
Other expenses	250,811	251,211	256,361	326,398
Net income	39,578	30,222	78,419	174,479
Net income per common share:				
Basic	0.10	0.07	0.17	0.39
Diluted	0.09	0.07	0.17	0.38
Cash flow provided by operating activities	91,627	153,999	147,904	136,155
Cash flow used in investing activities	(51,376)	(83,522)	(81,834)	(116,544)
Cash flow provided by (used in) financing activities	(40,578)	(69,908)	679	(47,645)

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2019, to ensure that information that is required to be disclosed in the reports the Company files and submits under the Securities Exchange Act of 1934 is recorded; that it is processed, summarized and reported within the time periods specified in the SEC's rules and forms; and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Evaluation of Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we have determined that, during the fourth quarter of fiscal 2019, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of the end of the period covered by this report based on the framework in "Internal Control – Integrated Framework" (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, our Chief Executive Officer and our Chief Financial Officer concluded that our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

The effectiveness of our internal control over financial reporting as of December 31, 2019, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in the report that appears herein.

Important Considerations

The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to various inherent limitations, including cost limitations, judgments used in decision making, assumptions about the likelihood of future events, the soundness of our systems, the possibility of human error, and the risk of fraud. Moreover, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions and the risk that the degree of compliance with policies or procedures may deteriorate over time. Because of these limitations, there can be no assurance that any system of disclosure controls and procedures or internal control over financial reporting will be successful in preventing all errors or fraud or in making all material information known in a timely manner to the appropriate levels of management.

Item 9B. Other Information

None.

Denbury Resources Inc.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Except as disclosed below, information as to Item 10 will be set forth in the Proxy Statement ("Proxy Statement") for the 2020 Annual Meeting of Shareholders to be held May 28, 2020 ("Annual Meeting") and is incorporated herein by reference.

Code of Ethics

We have adopted a Code of Ethics for Senior Financial Officers. This Code of Ethics, including any amendments or waivers, is posted on our website at www.denbury.com.

Item 11. Executive Compensation

Information as to Item 11 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information as to Item 12 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information as to Item 13 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information as to Item 14 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Denbury Resources Inc.

PART IV

Item 15. Exhibits and Financial Statement Schedules

Financial Statements and Schedules. Financial statements and schedules filed as a part of this report are presented on page 61. All financial statement schedules have been omitted because they are not applicable, or the required information is presented in the financial statements or the notes to consolidated financial statements.

Exhibits. The following exhibits are included as part of this report.

Exhibit No.	Exhibit
3(a)	Second Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on October 30, 2014 (incorporated by reference to Exhibit 3(a) of Form 10-Q filed by the Company on November 7, 2014, File No. 001-12935).
3(b)	Second Amended and Restated Bylaws of Denbury Resources Inc. as of November 4, 2014 (incorporated by reference to Exhibit 3(b) of Form 10-Q filed by the Company on November 7, 2014, File No. 001-12935).
3(c)	Certificate of Amendment of Second Restated Certificate of Incorporation of Denbury Resources, Inc., filed with the Delaware Secretary of State on May 22, 2019 (incorporated by reference to Exhibit 3.1 on Form 8-K filed by the Company on May 28, 2019, File No. 001-12935).
4(a)	Indenture for 6⅜% Senior Subordinated Notes due 2021, dated as of February 17, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on February 22, 2011, File No. 001-12935).
4(b)	First Supplemental Indenture for 6⅜% Senior Subordinated Notes due 2021, dated as of December 31, 2014, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(x) of Form 10-K filed by the Company on February 27, 2015, File No. 001-12935).
4(c)	Second Supplemental Indenture for 6⅜% Senior Subordinated Notes due 2021, dated as of September 8, 2017, by and among Denbury Resources Inc., certain of its subsidiaries, and Wilmington Trust, National Association, as Trustee (incorporated by reference to Exhibit 4(a) of Form 10-Q filed by the Company on November 7, 2017, File No. 001-12935).
4(d)	Indenture for 4⅝% Senior Subordinated Notes due 2023, dated as of February 5, 2013, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on February 5, 2013, File No. 001-12935).
4(e)	First Supplemental Indenture for 4⅝% Senior Subordinated Notes due 2023, dated as of December 31, 2014, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(z) of Form 10-K filed by the Company on February 27, 2015, File No. 001-12935).
4(f)	Second Supplemental Indenture for 4⅝% Senior Subordinated Notes due 2023, dated as of September 8, 2017, by and among Denbury Resources Inc., certain of its subsidiaries, and Wilmington Trust, National Association, as Trustee (incorporated by reference to Exhibit 4(b) of Form 10-Q filed by the Company on November 7, 2017, File No. 001-12935).
4(g)	Indenture for 5½% Senior Subordinated Notes due 2022, dated as of April 30, 2014, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on May 1, 2014, File No. 001-12935).
4(h)	First Supplemental Indenture for 5½% Senior Subordinated Notes due 2022, dated as of December 31, 2014, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(bb) of Form 10-K filed by the Company on February 27, 2015, File No. 001-12935).

Denbury Resources Inc.

Exhibit No.	Exhibit
4(i)	Second Supplemental Indenture for 5½% Senior Subordinated Notes due 2022, dated as of September 8, 2017, by and among Denbury Resources Inc., certain of its subsidiaries, and Wilmington Trust, National Association, as Trustee (incorporated by reference to Exhibit 4(c) of Form 10-Q filed by the Company on November 7, 2017, File No. 001-12935).
4(j)	Indenture for 9% Senior Secured Second Lien Notes due 2021, dated as of May 10, 2016, by and among Denbury Resources Inc., certain of its subsidiaries, and Wilmington Trust, National Association, as Trustee and Collateral Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on May 11, 2016, File No. 001-12935).
4(k)	First Supplemental Indenture for 9% Senior Subordinated Notes due 2021, dated as of September 8, 2017, by and among Denbury Resources Inc., certain of its subsidiaries, and Wilmington Trust, National Association, as Trustee and Collateral Trustee (incorporated by reference to Exhibit 4(d) of Form 10-Q filed by the Company on November 7, 2017, File No. 001-12935).
4(l)	Indenture for 9¼% Senior Secured Second Lien Notes due 2022, dated as of December 6, 2017, by and among Denbury Resources Inc., certain of its subsidiaries, and Wilmington Trust, National Association, as Trustee and Collateral Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on December 12, 2017, File No. 001-12935).
4(m)	Indenture for 3½% Convertible Senior Notes due 2024, dated as of December 6, 2017, by and among Denbury Resources Inc., certain of its subsidiaries, and Wilmington Trust, National Association, as Trustee (incorporated by reference to Exhibit 4.3 of Form 8-K filed by the Company on December 12, 2017, File No. 001-12935).
4(n)	Indenture, dated as of January 9, 2018, among the Company, the Subsidiary Guarantors named therein, and Wilmington Trust, National Association, as Trustee, with respect to $59,439,000 aggregate principal amount of 5% Convertible Senior Notes due 2023 (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on January 11, 2018, File No. 001-12935).
4(o)	Indenture, dated as of August 21, 2018, among the Company, the Subsidiary Guarantors named therein, and Wilmington Trust, National Association, as Trustee and Collateral Trustee, with respect to $450,000,000 aggregate principal amount of 7½% Senior Secured Second Lien Notes due 2024 (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on August 22, 2018, File No. 001-12935).
4(p)	Indenture, dated as of June 19, 2019, among the Company, the Subsidiary Guarantors named therein, and Wilmington Trust, National Association, as Trustee and Collateral Trustee, with respect to $528,026,000 aggregate principal amount of 7¾% Senior Secured Second Lien Notes due 2024 (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on June 24, 2019, File No. 001-12935).
4(q)	Indenture, dated as of June 19, 2019, among the Company, the Subsidiary Guarantors named therein, and Wilmington Trust, National Association, as Trustee, with respect to $245,548,000 aggregate principal amount of 6⅜% Convertible Senior Notes due 2024 (incorporated by reference to Exhibit 4.3 of Form 8-K filed by the Company on June 24, 2019, File No. 001-12935).
4(r)*	Description of Denbury Resources Inc. equity securities registered under Section 12 of the Securities Exchange Act of 1934, as amended.
10(a)	Amended and Restated Credit Agreement, dated as of December 9, 2014, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lending institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on December 15, 2014, File No. 001-12935).
10(b)	First Amendment to Amended and Restated Credit Agreement, dated as of May 4, 2015, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on May 6, 2015, File No. 001-12935).

Denbury Resources Inc.

Exhibit No.	Exhibit
10(c)	Second Amendment to Amended and Restated Credit Agreement, dated as of February 17, 2016, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on February 23, 2016, File No. 001-12935).
10(d)	Third Amendment to Amended and Restated Credit Agreement, dated as of April 18, 2016, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on April 20, 2016, File No. 001-12935).
10(e)	Fourth Amendment to Amended and Restated Credit Agreement, dated as of May 3, 2017, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on May 4, 2017, File No. 001-12935).
10(f)	Fifth Amendment to Amended and Restated Credit Agreement, dated as of November 6, 2017, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on November 7, 2017, File No. 001-12935).
10(g)	Sixth Amendment to Amended and Restated Credit Agreement, dated as of August 13, 2018, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on August 14, 2018, File No. 001-12935).
10(h)	Seventh Amendment to Amended and Restated Credit Agreement, dated as of May 3, 2019, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10(a) on Form 10-Q filed by the Company on May 9, 2019, File No. 001-12935).
10(i)	Collateral Trust Agreement, dated as of May 10, 2016, by and among Denbury Resources Inc., certain of its subsidiaries, and Wilmington Trust, National Association, as Trustee and Collateral Trustee (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on May 11, 2016, File No. 001-12935).
10(j)	Collateral Trust Joinder, dated as of December 6, 2017, by and among Denbury Resources Inc., certain of its subsidiaries, and Wilmington Trust, National Association, as Trustee and Collateral Trustee (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on December 12, 2017, File No. 001-12935).
10(k)	Collateral Trust Joinder, dated as of January 9, 2018, among the Company, the Subsidiary Guarantors named therein, Wilmington Trust, National Association, as Trustee, the other parity lien representatives from time to time party thereto and Wilmington Trust, National Association, as Collateral Trustee (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on January 11, 2018, File No. 001-12935).
10(l)	Collateral Trust Joinder, dated as of August 21, 2018, between Wilmington Trust, National Association, as Trustee, and Wilmington Trust, National Association, as Collateral Trustee (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on August 22, 2018, File No. 001-12935).
10(m)	Intercreditor Agreement, dated as of May 10, 2016, by and between JPMorgan Chase Bank, N.A., as Priority Lien Agent, and Wilmington Trust, National Association, as Collateral Trustee (incorporated by reference to Exhibit 10.2 of Form 8-K filed by the Company on May 11, 2016, File No. 001-12935).
10(n)	Priority Confirmation Joinder, dated as of December 6, 2017, by and between JPMorgan Chase Bank, N.A., as Priority Lien Agent, and Wilmington Trust, National Association, as Collateral Trustee (incorporated by reference to Exhibit 10.2 of Form 8-K filed by the Company on December 12, 2017, File No. 001-12935).
10(o)	Priority Confirmation Joinder, dated as of August 21, 2018, by and between JPMorgan Chase Bank, N.A., as Priority Lien Agent, and Wilmington Trust, National Association, as Collateral Trustee (incorporated by reference to Exhibit 10.2 of Form 8-K filed by the Company on August 22, 2018, File No. 001-12935).

Denbury Resources Inc.

Exhibit No.	Exhibit
10(p)	Priority Confirmation Joinder, dated as of June 19, 2019, by and between JPMorgan Chase Bank, N.A., as Priority Lien Agent, and Wilmington Trust, National Association, as Collateral Trustee (incorporated by reference to Exhibit 10.2 on Form 8-K filed by the Company on June 24, 2019, File No. 001-12935).
10(q)	Priority Confirmation Joinder, dated as of July 1, 2019, by and between JPMorgan Chase Bank, N.A., as Priority Lien Agent, and Wilmington Trust, National Association, as Collateral Trustee (incorporated by reference to Exhibit 10.2 of Form 8-K filed by the Company on July 2, 2019, File No. 001-12935).
10(r)	Collateral Trust Joinder, dated as of January 9, 2018, among the Company, the Subsidiary Guarantors named therein, Wilmington Trust, National Association, as Trustee, the other parity lien representatives from time to time party thereto and Wilmington Trust, National Association, as Collateral Trustee (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on January 11, 2018, File No. 001-12935).
10(s)	Collateral Trust Joinder, dated as of June 19, 2019, by and between Wilmington Trust, National Association, as Trustee, and Wilmington Trust, National Association, as Collateral Trustee (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on June 24, 2019, File No. 001-12935).
10(t)	Collateral Trust Joinder, dated as of July 1, 2019, by and between Wilmington Trust, National Association, as Trustee, and Wilmington Trust, National Association, as Collateral Trustee (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on July 2, 2019, File No. 001-12935).
10(u)	Pipeline Financing Lease Agreement, dated as of May 30, 2008, by and between Genesis NEJD Pipeline, LLC, as Lessor, and Denbury Onshore, LLC, as Lessee (incorporated by reference to Exhibit 99.1 of Form 8-K filed by the Company on June 5, 2008, File No. 001-12935).
10(v)	Transportation Services Agreement, dated as of May 30, 2008, by and between Genesis Free State Pipeline, LLC and Denbury Onshore, LLC (incorporated by reference to Exhibit 99.2 of Form 8-K filed by the Company on June 5, 2008, File No. 001-12935).
10(w)**	Form of Indemnification Agreement, by and between Denbury Resources Inc. and its officers and directors (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on November 7, 2017, File No. 001-12935).
10(x)**	Denbury Resources Inc. Director Deferred Compensation Plan, as amended and restated effective as of December 16, 2015 (incorporated by reference to Exhibit 10(i) of Form 10-K filed by the Company on February 26, 2016, File No. 001-12935).
10(y)**	Denbury Resources Inc. Severance Protection Plan, as amended and restated effective as of March 29, 2018 (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on May 10, 2018, File No. 001-12935).
10(z)**	Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated effective as of March 29, 2018 (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on May 10, 2018, File No. 001-12935).
10(aa)**	Denbury Resource Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated effective as of March 28, 2019 (incorporate by reference to Exhibit 10.1 on Form 8-K filed by the Company on May 28, 2019, File No. 001-12935).
10(bb)**	2004 Form of Restricted Stock Award that vests on retirement for grants to officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(l) of Form 10-K filed by the Company on March 15, 2005, File No. 001-12935).
10(cc)**	2016 Form of TSR Performance Award-Equity under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on May 6, 2016, File No. 001-12935).

Denbury Resources Inc.

Exhibit No.	Exhibit
10(dd)**	2016 Form of TSR Performance Award-Cash under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on May 6, 2016, File No. 001-12935).
10(ee)**	2016 Form of EBITDAX Performance Award-Equity under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(mm) of Form 10-K filed by the Company on March 1, 2017, File No. 001-12935).
10(ff)**	2016 Form of EBITDAX Performance Award-Cash under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(nn) of Form 10-K filed by the Company on March 1, 2017, File No. 001-12935).
10(gg)**	2016 Form of Oil Price Change vs. TSR Performance Award, under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(e) of Form 10-Q filed by the Company on May 6, 2016, File No. 001-12935).
10(hh)**	2016 Form of Restricted Share Award to officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(pp) of Form 10-K filed by the Company on March 1, 2017, File No. 001-12935).
10(ii)**	2016 Form of Restricted Stock Award to non-employee directors pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(qq) of Form 10-K filed by the Company on March 1, 2017, File No. 001-12935).
10(jj)**	2016 Form of Deferred Stock Unit Award pursuant to the Director Deferred Compensation Plan (with respect to deferred long-term incentive awards) (incorporated by reference to Exhibit 10(rr) of Form 10-K filed by the Company on March 1, 2017, File No. 001-12935).
10(kk)**	Standalone Restricted Share New Hire Inducement Award Agreement between Denbury Resources Inc. and Christian S. Kendall, dated September 8, 2015 (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on September 8, 2015, File No. 001-12935).
10(ll)**	Restricted Stock Officer Promotion Award pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(tt) of Form 10-K filed by the Company on March 1, 2017, File No. 001-12935).
10(mm)**	2017 Form of TSR Performance Award-Equity under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on May 5, 2017, File No. 001-12935).
10(nn)**	2017 Form of TSR Performance Award-Cash under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on May 5, 2017, File No. 001-12935).
10(oo)**	2017 Form of EBITDAX Performance Award-Equity under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on May 5, 2017, File No. 001-12935).
10(pp)**	2017 Form of EBITDAX Performance Award-Cash under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(d) of Form 10-Q filed by the Company on May 5, 2017, File No. 001-12935).
10(qq)**	2017 Form of Oil Change vs. TSR Performance Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(e) of Form 10-Q filed by the Company on May 5, 2017, File No. 001-12935).

Denbury Resources Inc.

Exhibit No.	Exhibit
10(rr)**	2017 Form of Restricted Share Award to officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on August 8, 2017, File No. 001-12935).
10(ss)**	2017 Form of Restricted Share Award to non-employee directors pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on August 8, 2017, File No. 001-12935).
10(tt)**	2018 Form of TSR Performance Award-Cash under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on May 10, 2018, File No. 001-12935).
10(uu)**	2019 Form of TSR Performance Award-Cash under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on May 9, 2019, File No. 001-12935).
10(vv)**	2018 Form of TSR Performance Award-Equity under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(d) of Form 10-Q filed by the Company on May 10, 2018, File No. 001-12935).
10(ww)**	2019 Form of TSR Performance Award-Equity under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on May 9, 2019, File No. 001-12935).
10(xx)**	2018 Form of Debt-Adjusted Reserves Growth Per Share Performance Award-Cash under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(e) of Form 10-Q filed by the Company on May 10, 2018, File No. 001-12935).
10(yy)**	2019 Form of Debt-Adjusted Reserves Growth Per Share Performance Award-Cash under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(d) of Form 10-Q filed by the Company on May 9, 2019, File No. 001-12935).
10(zz)**	2018 Form of Debt-Adjusted Reserves Growth Per Share Performance Award-Equity under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(f) of Form 10-Q filed by the Company on May 10, 2018, File No. 001-12935).
10(aaa)**	2019 Form of Debt-Adjusted Reserves Growth Per Share Performance Award-Equity under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(e) of Form 10-Q filed by the Company on May 9, 2019, File No. 001-12935).
10(bbb)**	2018 Form of Restricted Share Award to officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on August 9, 2018, File No. 001-12935).
10(ccc)**	2019 Form of Restricted Stock Unit Award to officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on November 8, 2019, File No. 001-12935).
10(ddd)**	2018 Form of Restricted Share Award to non-employee directors pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on August 9, 2018, File No. 001-12935).
21*	List of subsidiaries of Denbury Resources Inc.
23(a)*	Consent of PricewaterhouseCoopers LLP.
23(b)*	Consent of DeGolyer and MacNaughton.

Denbury Resources Inc.

Exhibit No.	Exhibit
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99*	The summary of DeGolyer and MacNaughton's Report as of December 31, 2019, on oil and gas reserves (SEC Case) dated February 14, 2020.
101.INS*	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Document Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

*   Included herewith.
** Compensation arrangements.

Item 16. Form 10-K Summary

None.

Denbury Resources Inc.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Denbury Resources Inc. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	DENBURY RESOURCES INC.
February 26, 2020	/s/ Mark C. Allen
	Mark C. Allen Executive Vice President and Chief Financial Officer
February 26, 2020	/s/ Alan Rhoades
	Alan Rhoades Vice President and Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of Denbury Resources Inc. and in the capacities and on the dates indicated.

February 26, 2020	/s/ Christian S. Kendall
	Christian S. Kendall Director, President and Chief Executive Officer (Principal Executive Officer)
February 26, 2020	/s/ Mark C. Allen
	Mark C. Allen Executive Vice President and Chief Financial Officer (Principal Financial Officer)
February 26, 2020	/s/ Alan Rhoades
	Alan Rhoades Vice President and Chief Accounting Officer (Principal Accounting Officer)
February 26, 2020	/s/ John P. Dielwart
	John P. Dielwart Director
February 26, 2020	/s/ Michael B. Decker
	Michael B. Decker Director
February 26, 2020	/s/ Gregory L. McMichael
	Gregory L. McMichael Director
February 26, 2020	/s/ Kevin O. Meyers
	Kevin O. Meyers Director

Denbury Resources Inc.

February 26, 2020	/s/ Lynn A. Peterson
	Lynn A. Peterson Director
February 26, 2020	/s/ Randy Stein
	Randy Stein Director
February 26, 2020	/s/ Mary M. VanDeWeghe
	Mary M. VanDeWeghe Director

Exhibit 4r

DESCRIPTION OF CAPITAL STOCK

General

As of January 31, 2020, we are authorized to issue up to 775,000,000 shares of stock, including up to 750,000,000 shares of common stock, par value $.001 per share, and up to 25,000,000 shares of preferred stock, par value $.001 per share. As of January 31, 2020, we had 506,382,897 shares of common stock and no shares of preferred stock outstanding.

The following is a summary of the key terms and provisions of our equity securities. You should refer to the applicable provisions of our Second Restated Certificate of Incorporation, bylaws and the Delaware General Corporation Law for a complete statement of the terms and rights of our capital stock.

Common Stock

Voting rights. Each holder of common stock is entitled to one vote per share on each matter submitted to a vote of shareholders. Subject to the rights, if any, of the holders of any series of preferred stock pursuant to applicable law or the provision of the certificate of designation creating that series, all voting rights are vested in the holders of shares of common stock. Holders of shares of common stock have non-cumulative voting rights, which means that the holders of more than 50% of the shares voting for the election of directors can elect 100% of the directors, and the holders of the remaining shares voting for the election of directors will not be able to elect any directors.

Dividends. Dividends may be paid to holders of common stock when, as and if declared by the board of directors (the "Board") out of funds legally available for their payment, subject to the rights of holders of any preferred stock. We have not paid dividends on our common stock since the fourth quarter of 2015 and have no current plans to resume common stock dividends.

Rights upon liquidation. In the event of our voluntary or involuntary liquidation, dissolution or winding up, holders of our common stock will be entitled to share equally, in proportion to the number of shares of common stock held by them, in any of our assets available for distribution after the payment in full of all debts and distributions and after holders of all series of outstanding preferred stock, if any, have received their liquidation preferences in full.

Non-assessable. All outstanding shares of common stock are fully paid and non-assessable.

Other rights and preferences. Holders of common stock are not entitled to preemptive, conversion or exchange rights. Our common stock has no sinking fund or redemption provisions. Holders of common stock may act by unanimous written consent.

Listing. Our outstanding shares of common stock are listed on the New York Stock Exchange under the trading symbol "DNR."

Preferred Stock

The following description of the terms of the preferred stock sets forth certain general terms and provisions of our authorized preferred stock. If we offer preferred stock, a description will be filed with the Securities and Exchange Commission and the specific designations and rights, as determined by the Board, will be described in such filing, including the following terms:

- the series, the number of shares offered and the liquidation value of the preferred stock;
- the price at which the preferred stock will be issued;
- the dividend rate, the dates on which the dividends will be payable and other terms relating to the payment of dividends on the preferred stock;
- the liquidation preference of the preferred stock;
- the voting rights of the preferred stock, if any;
- whether the preferred stock is redeemable or subject to a sinking fund, and the terms of any such redemption or sinking fund;
- whether the preferred stock is convertible or exchangeable for any other securities, and the terms of any such conversion; and
- any additional rights, preferences, qualifications, limitations and restrictions of the preferred stock.

Except where otherwise set forth in a resolution of the Board providing for the issuance of any series of preferred stock, the number of shares comprising such series may be increased or decreased (but not below the number of shares then outstanding) from time to time by like action of the Board. The shares of preferred stock of any one series shall be identical with the other shares in the same series in all respects except as to the dates from and after which dividends thereon shall cumulate, if cumulative.

The description of the terms of the preferred stock to be set forth in the applicable filing will not be complete and will be subject to and qualified in its entirety by reference to the certificate of designation relating to the applicable series of preferred stock.

Undesignated preferred stock may enable the Board to render more difficult or to discourage an attempt to obtain control of us by means of a tender offer, proxy contest, merger or otherwise, and to thereby protect the continuity of our management. The issuance of shares of preferred stock may adversely affect the rights of holders of our common stock. For example, any preferred stock issued may rank prior to our common stock as to dividend rights, liquidation preference or both, may have full or limited voting rights and may be convertible into shares of common stock. As a result, the issuance of shares of preferred stock may discourage bids for our common stock or may otherwise adversely affect the market price of our common stock or any existing preferred stock.

Any preferred stock will, when issued, be fully paid and non-assessable.

Exhibit 21

LIST OF SUBSIDIARIES

Name of Subsidiary	Jurisdiction of Organization
Denbury Operating Company	Delaware
Denbury Onshore, LLC	Delaware
Denbury Pipeline Holdings, LLC	Delaware
Denbury Holdings, Inc.	Delaware
Denbury Green Pipeline – Texas, LLC	Delaware
Greencore Pipeline Company, LLC	Delaware
Denbury Gulf Coast Pipelines, LLC	Delaware

Exhibit 23(a)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-01006, 333-27995, 333-55999, 333-70485, 333-39172, 333-39218, 333-39224, 333-63198, 333-90398, 333-106253, 333-116249, 333-143848, 333-160178, 333-167480, 333-175273, 333-189438, 333-206320, 333-206808, 333-212402, 333-218941 and 333-232166), Form S-3 (No. 333-222066) and Form S-4 (No. 333-228935) of Denbury Resources Inc. of our report dated February 26, 2020 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas

February 26, 2020

Exhibit 23(b)

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 25, 2020

Denbury Resources Inc.
5320 Legacy Drive
Plano, Texas 75024

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton, to the inclusion of our report of third party dated February 14, 2020, regarding the proved reserves of Denbury Resources Inc., and to the inclusion of information taken from our reports entitled "Report as of December 31, 2019 on Reserves and Revenue of Certain Properties with interests attributable to Denbury Resources Inc.," "Report as of December 31, 2018 on Reserves and Revenue of Certain Properties with interests attributable to Denbury Resources Inc. SEC Case," and "Report as of December 31, 2017 on Reserves and Revenue of Certain Properties owned by Denbury Resources Inc. SEC Case" in the Annual Report on Form 10-K of Denbury Resources Inc. for the year ended December 31, 2019.

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

Exhibit 31(a)

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Christian S. Kendall, certify that:

1. I have reviewed this report on Form 10-K of Denbury Resources Inc. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 26, 2020

/s/ Christian S. Kendall

Christian S. Kendall
Director, President and Chief Executive Officer

Exhibit 31(b)

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark C. Allen, certify that:

1. I have reviewed this report on Form 10-K of Denbury Resources Inc. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 26, 2020

/s/ Mark C. Allen

Mark C. Allen

Executive Vice President, Chief Financial Officer, Treasurer, and Assistant Secretary

Exhibit 32

Certification of Chief Executive Officer and Chief Financial Officer
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the accompanying Annual Report on Form 10-K for the year ended December 31, 2019 (the Report) of Denbury Resources Inc. (Denbury) as filed with the Securities and Exchange Commission, each of the undersigned, in his capacity as an officer of Denbury, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Denbury.

Dated: February 26, 2020

/s/ Christian S. Kendall
Christian S. Kendall
Director, President and Chief Executive Officer

Dated: February 26, 2020

/s/ Mark C. Allen
Mark C. Allen
Executive Vice President, Chief Financial Officer, Treasurer, and Assistant Secretary

Exhibit 99

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 14, 2020

Denbury Resources Inc.
5320 Legacy Drive
Plano, Texas 75024

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2019, of the extent and value of the estimated net proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain properties in which Denbury Resources Inc. (Denbury) has represented it holds an interest. This evaluation was completed on February 14, 2020. The properties evaluated herein are located in Louisiana, Mississippi, Montana, North Dakota, Texas, and Wyoming. Denbury has represented that these properties account for 100 percent on a net equivalent barrel basis of Denbury's net proved reserves as of December 31, 2019. The net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the Securities and Exchange Commission (SEC) of the United States. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S-K and is to be used for inclusion in certain SEC filings by Denbury.

Estimates of proved carbon dioxide reserves are also included herein. While Rules 4-10(a) (1)-(32) of Regulation S-X of the SEC do not allow the reporting of carbon dioxide reserves, at Denbury's request carbon dioxide reserves were evaluated using the technical and economic criteria of the SEC for petroleum reserves.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2019. Certain of the properties evaluated herein in Montana, North Dakota, and Wyoming are subject to net profit interest (NPI) payable to other parties. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Denbury after deducting all interests held by others and after accounting for the portion of the gross reserves attributable to the NPI owners.

Values for proved reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting NPI payments, production and ad valorem taxes, operating expenses, capital costs, and abandonment costs from future gross revenue. Operating expenses include field operating expenses, transportation and processing expenses, compression charges, and an allocation of overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. Abandonment costs are represented by Denbury to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. At the request of Denbury, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a nominal discount rate of 10 percent per year compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

Estimates of reserves and revenue should be regarded only as estimates that may change as production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was obtained from Denbury and from public sources. In the preparation of this report we have relied, without independent verification, upon information furnished by Denbury with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Definition of Reserves

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4-10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Denbury, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

The proved undeveloped reserves estimates were based on opportunities identified in the plan of development provided by Denbury.

Denbury has represented that its senior management is committed to the development plan provided by Denbury and that Denbury has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and original gas in place (OGIP). Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material-balance methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP and OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors based on an analysis of reservoir performance, including production rate, reservoir pressure, and reservoir fluid properties. Certain properties evaluated herein are produced using carbon dioxide enhanced oil recovery methods involving continuous carbon dioxide flooding operations. Therefore, carbon dioxide versus oil ratios and carbon dioxide injection volumes were analyzed and projected and were used in the estimation of reserves when applicable.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production as defined under the Definition of Reserves heading of this report.

In certain cases, reserves were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Denbury from wells drilled through December 31, 2019, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available for certain properties only through November 2019. Estimated cumulative production, as of December 31, 2019, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for 1 month.

Oil and condensate reserves estimated herein are to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C_{5+}) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions and are the result of low-temperature plant processing. Oil, condensate, and NGL reserves included in this report are expressed in thousands of barrels (Mbbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil, condensate, and NGL reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas reserves estimated herein are reported as sales gas. Gas reserves are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at the pressure base of the state in which the reserves are located. Gas reserves included in this report are expressed in millions of cubic feet (MMcf).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

At the request of Denbury, sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

Primary Economic Assumptions

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Denbury. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the revenue values reported herein:

Oil, Condensate, and NGL Prices

Denbury has represented that the oil, condensate, and NGL prices were based on a reference price, calculated as the unweighted arithmetic average of the first--day-of-the-monthprice for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Denbury supplied differentials to the NYMEX reference price of $55.69 per barrel and the prices were held constant thereafter. The pre-NPI volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $55.55 per barrel of oil and condensate and $19.55 per barrel of NGL.

Gas Prices

Denbury has represented that the gas prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Denbury supplied differentials to the NYMEX gas reference price of $2.58 per million Btu and the prices were held constant thereafter. Btu factors provided by Denbury were used to convert prices from dollars per million Btu to dollars per thousand cubic feet. The pre-NPI volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $1.951 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using rates provided by Denbury, including, where appropriate, abatements for enhanced recovery programs. Ad valorem taxes were calculated using rates provided by Denbury based on recent payments.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Denbury and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using 2019 values, provided by Denbury, and were not adjusted for inflation. In certain cases, future expenditures, either higher or lower than current expenditures, may have been used because of anticipated changes in operating conditions, but no general escalation that might result from inflation was applied. Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by Denbury and were not adjusted for inflation. The abandonment costs were provided by Denbury at the field level (and the well level where appropriate). These abandonment costs have not been allocated to the various individual properties within each field. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of undeveloped reserves estimated herein.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, NGL, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the FASB and Rules 4-10(a) (1)-(32) of Regulation S-X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S-K of the SEC; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein, (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year, and (iii) the reporting of carbon dioxide reserves is not permitted under SEC regulations.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Summary of Conclusions

The estimated net proved reserves, as of December 31, 2019, of the properties evaluated herein were based on the definition of proved reserves of the SEC and are summarized as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (Mboe):

	Estimated by DeGolyer and MacNaughton		
	Net Post-NPI Proved Reserves as of December 31, 2019		
	Total Liquids (Mbbl)	**Sales Gas (MMcf)**	**Oil Equivalent (Mboe)**
Proved Developed	202,816	24,333	206,872
Proved Undeveloped	23,317	1	23,317
Total Proved	**226,133**	**24,334**	**230,189**

Notes:

1. Sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.
2. Total liquids include 3,582 Mbbl of proved developed NGL.

In addition to the gas reserves shown in the foregoing tabulation, Denbury's net proved carbon dioxide gas reserves in Mississippi and Wyoming, as of December 31, 2019, were estimated to be 4,933,647 MMcf. This amount includes 4,542,964

MMcf of developed reserves and 390,683 MMcf of undeveloped reserves. Denbury's proved carbon dioxide gas reserves attributable to its working interest were estimated to be 4,696,934 MMcf, of which 4,214,563 MMcf are developed. The gross proved carbon dioxide reserves for the evaluated properties were estimated to be 8,147,062 MMcf, of which 7,652,062 MMcf are developed. The proved carbon dioxide reserves estimated herein were prepared using the reserves definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the SEC. No revenue estimates have been made for the carbon dioxide reserves.

The estimated future revenue to be derived from the production and sale of the net proved reserves, as of December 31, 2019, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed (M$)	**Total Proved (M$)**
Future Gross Revenue (Post-NPI)	11,146,662	12,494,358
Production and Ad Valorem Taxes	834,124	912,711
Operating Expenses	5,438,189	5,900,899
Capital Costs	414,463	770,721
Abandonment Costs	649,698	664,213
Future Net Revenue	3,810,188	4,245,814
Present Worth at 10 Percent	2,498,187	2,615,668

Note: Future income taxes have not been taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2019, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Denbury. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Denbury. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

/s/ DeGolyer and MacNaughton

DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

/s/ Gregory K. Graves

Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Gregory K. Graves, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which firm did prepare the report of third party addressed to Denbury Resources Inc. dated February 14, 2020, and that I, as Senior Vice President, was responsible for the preparation of this report of third party.

2. That I attended the University of Texas at Austin, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 1984; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and that I have in excess of 35 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Gregory K. Graves

Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton